Nuclear Operating Company

South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

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U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, MD 20852-2746

South Texas Project
Units 1 and 2
Docket Nos. STN 50-498, STN 50-499
Response to Requests for Additional Information for the
South Texas Project License Renewal Application (TAC Nos. ME4936 and ME4937)

References: 1. STPNOC Letter dated October 25, 2010, from G. T. Powell to NRC Document Control Desk, "License Renewal Application" (NOC-AE-10002607) (ML103010257)

2. NRC Letter dated September 22, 2011, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2 License Renewal Application – Aging Management Review, Set 1 (TAC Nos. ME4936 and ME4937)" (ML11250A043)

By Reference 1, STP Nuclear Operating Company (STPNOC) submitted a License Renewal Application (LRA) for South Texas Project (STP) Units 1 and 2. By Reference 2, the NRC staff requests additional information for review of the STP LRA. STPNOC's response to the request for additional information is provided in Enclosure 1 to this letter. Changes to LRA pages described in Enclosure 1 are depicted in line-in/line-out pages provided in Enclosure 2. The response to RAI 3.5.1.59-1 will be provided in a separate submittal by December 8, 2011.

There are no new regulatory commitments in this letter.

Should you have any questions regarding this letter, please contact either Arden Aldridge, STP License Renewal Project Lead, at (361) 972-8243 or Ken Taplett, STP License Renewal Project regulatory point-of-contact, at (361) 972-8416.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 11/21/2011
Date

D. W. Rencurrel
Senior Vice President,
Technical Support & Oversight

PLW

Enclosure: 1. STPNOC Response to Requests for Additional Information
2. STP LRA Changes with line-in/line-out annotation

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NRR

cc:

(paper copy)

Regional Administrator, Region IV
U. S. Nuclear Regulatory Commission
612 East Lamar Blvd, Suite 400
Arlington, Texas 76011-4125

Balwant K. Singal
Senior Project Manager
U.S. Nuclear Regulatory Commission
One White Flint North (MS 8B1)
11555 Rockville Pike
Rockville, MD 20852

Senior Resident Inspector
U. S. Nuclear Regulatory Commission
P. O. Box 289, Mail Code: MN116
Wadsworth, TX 77483

C. M. Canady
City of Austin
Electric Utility Department
721 Barton Springs Road
Austin, TX 78704

John W. Daily
License Renewal Project Manager (Safety)
U.S. Nuclear Regulatory Commission
One White Flint North (MS O11-F1)
Washington, DC 20555-0001

Tam Tran
License Renewal Project Manager
(Environmental)
U. S. Nuclear Regulatory Commission
One White Flint North (MS O11F01)
Washington, DC 20555-0001

(electronic copy)

A. H. Gutterman, Esquire
Kathryn M. Sutton, Esquire
Morgan, Lewis & Bockius, LLP

John Ragan
Chris O'Hara
Jim von Suskil
NRG South Texas LP

Kevin Pollo
Richard Pena
City Public Service

Peter Nemeth
Crain Caton & James, P.C.

C. Mele
City of Austin

Richard A. Ratliff
Alice Rogers
Texas Department of State Health Services

Balwant K. Singal
John W. Daily
Tam Tran
U. S. Nuclear Regulatory Commission

Enclosure 1

STPNOC Response to Requests for Additional Information

Set 1

STPNOC Response to Requests for Additional Information

SOUTH TEXAS PROJECT, UNITS 1 AND 2
REQUESTS FOR ADDITIONAL INFORMATION -
AGING MANAGEMENT REVIEW SET 1
(TAC NOS. ME4936 AND ME4937)

Water Chemistry (002) and Internal Surfaces (039)

RAI 3.3.2.3.19-1

Background:

In license renewal application (LRA) Table 3.3.2-19, the applicant states that a Chemical and Volume Control System stainless steel pump and valve exposed to zinc acetate will be managed for loss of material by the Water Chemistry program. LRA Table 3.3.2-19 also states that a thermoplastic tank exposed to zinc acetate will be managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," does not specifically address the aging of stainless steel pumps, valves, or thermoplastics in a zinc acetate environment or identify associated aging effects.

Issue:

The aging of stainless steel and thermoplastic materials can be exacerbated under certain operating conditions and in the presence of certain impurities in the process stream. In order for the staff to evaluate whether the proposed aging management programs adequately manage the effects of aging for materials exposed to zinc acetate, additional information is needed regarding component/system operating parameters (i.e., zinc acetate concentration, design temperature and normal operating temperature) as well as information regarding the possible existence of impurities (e.g., oxygen, chlorides, fluorides, sulfates).

Request:

For each component subject to a loss of material and cracking aging effect in a zinc acetate environment, state the system's design temperature, minimum and maximum operating temperature, the normal operating temperature at which the component is exposed and the concentration of the zinc acetate. Also, provide all concentration limits that are specified for impurities in the system, including, but not limited to, oxygen, chlorides, fluorides, sulfates, etc.

STPNOC Response:

Stainless steel components in the zinc addition system have a design temperature of 300 degrees Fahrenheit except the metering pump casing which has a design temperature of 350 degrees Fahrenheit. The thermoplastic (MDPE) zinc mixing tank has a maximum design temperature of 140 degrees Fahrenheit with intermittent design service temperature to 160 degrees Fahrenheit.

The zinc mixing tank is used to mix the zinc acetate with demineralized water. The zinc solution is then added to the chemical and volume control system (CVCS) through the volume control tank (VCT) to reduce radiation fields in the reactor coolant system. The operating temperature of the VCT is 115 degrees Fahrenheit The zinc addition system components are located in the Mechanical Auxiliary Building (MAB), which is temperature controlled. The normal operating temperature of the zinc addition equipment and zinc solution before injection into the CVCS is ambient temperature of approximately 75 - 80 degrees Fahrenheit.

The zinc acetate is purchased as a powder that is mixed with demineralized water to form a 1 percent zinc acetate solution. The 1 percent solution provides a zinc concentration of 3019 parts per million in the zinc mixing tank which is metered into the CVCS using the metering pump. The maximum injection rate is 6.4 milliliters/minute (100% injection pump capacity). The zinc mixing tank is open and exposed to room atmosphere.

The zinc acetate powder maximum impurity concentrations are as follows:

Element(s)	PPM	Element(s)	PPM
Ag	<20	Os	<20
Al	<100	P, Pb, Pd, PO4	<20
As, Au	<20	Pr, Pt	<20
B, Ba, Be, Bi, Br	<20	Rb, Re, Rh, Ru	<20
Ca	<50	S	<50
Cd, Ce	<20	Sb, Sc, Se	<20
Cl	<50	Si	<50
Co, Cr, Cs, Cu	<20	Sm	<20
Dy	<20	Sn	<100
Dr, Eu	<20	SO4	<50
F	<20	Sr	<20
Fe	<30	Ta, Tb, Te, Th	<20
Ga,Gd,Ge	<20	Ti, Tl, Tm	<20
Hf,Hg,Ho	<20	U	<20
I, In, Ir	<20	V	<20
K	<20	W	<20
La, Li, Lu	<20	Y, Yb	<20
Mg, Mn, Mo	<20	Rare Earth	<20
N	<20	Insoluble in HCL	<100
Na	<50		
Nb, Nd, Ni	<20		

Note: PPM is parts per million

RAI 3.3.2.3.22-1

Background:

The LRA discusses the need to manage the aging of a variety of materials exposed to sodium hydroxide. For example:

- LRA Table 3.3.2-22, states that the stainless steel piping exposed to sodium hydroxide, in the Liquid Waste Processing System, will be managed for loss of material by the Water Chemistry program.
- LRA Table 3.3.2-27, states that the stainless steel accumulator, piping, pump, sight gauge, strainer, tank and valve exposed to sodium hydroxide, in the miscellaneous systems in scope only for criterion 10 CFR 54.4(a)(2), will be managed for loss of material by the Water Chemistry program and that the nickel alloy piping and valve exposed to sodium hydroxide will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.
- LRA Table 3.3.2-27 states that a glass sight gauge exposed to sodium hydroxide will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

The GALL Report does not specifically address the aging of glass, stainless steel, or nickel alloy piping and piping components in a sodium hydroxide environment or identify associated aging effects.

Issue:

The aging of stainless steel and glass can be exacerbated under certain operating conditions and in the presence of certain impurities in the process stream. In order for the staff to evaluate whether the proposed aging management programs adequately manage the effects of aging for materials exposed to sodium hydroxide, additional information is needed regarding component/system operating parameters (i.e., sodium hydroxide concentration, design temperature and normal operating temperature) as well as information regarding the possible existence of impurities (e.g., oxygen, chlorides, fluorides, sulfates).

Request:

The applicant is requested to identify, for each component subject to a loss of material aging effect in a sodium hydroxide environment, the system's design temperature, minimum and maximum operating temperature, the normal operating temperature at which the component is exposed and the concentration, of the sodium hydroxide. Also, provide all concentration limits that are specified for impurities in the system, including, but not limited to, oxygen, chlorides, fluorides, sulfates, etc.

STPNOC Response:

The liquid waste processing piping in LRA Table 3.3.2-22 with the sodium hydroxide internal environment interfaces with the solid waste processing chemical addition skid. A review of the solid waste processing system operation found that the chemical addition skid has never been used for sodium hydroxide addition. There are no plans to use the skid and there are no procedures for use of the system for sodium hydroxide addition. There are no stocks of sodium hydroxide at STP for this purpose. The sodium hydroxide skid is essentially abandoned-in-place. However, the equipment is not isolated from the plant system by cutting and capping and therefore remains in-scope for spatial interaction. The components are located in the Mechanical Auxiliary Building (MAB) which is temperature controlled. The normal temperature of the chemical addition tank and skid equipment in the solid waste processing system and the piping in the liquid processing system is considered ambient conditions in the MAB, which is approximately 75 - 80 degrees Fahrenheit.

The associated liquid processing system and solid waste processing system components internal environment will be changed from sodium hydroxide to raw water. Raw water is considered conservative since any demineralized water that may be residual in the system may not have been flushed recently. LRA Tables 3.3.2-22 and 3.3.2-27 will be revised to change the sodium hydroxide internal environment to raw water for the affected solid waste processing system components. Aging management program B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, will be used to manage the aging of these components. LRA Sections 3.3.2.1.22 and 3.3.2.1.27 will be revised to delete sodium hydroxide from the environments list.

Enclosure 2 provides line-in/line-out revision to LRA Sections 3.3.2.1.22 and 3.3.2.1.27 and Tables 3.3.2-22 and 3.3.2-27.

Thermal Aging Embrittlement (013)

RAI 3.1.1.57-1

Background:

LRA Section B2 states that the GALL Report aging management program (AMP) XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS)," is not credited. LRA Table 3.1.1, item 3.1.1.57 states that portions of the reactor coolant loops are constructed of CASS and that the straight piping pieces are centrifugally cast and that the fittings are statically cast. In addition, the applicant stated that the molybdenum and ferrite values for these fittings and piping pieces are below the industry accepted thermal aging significance threshold; therefore, thermal aging of CASS reactor coolant piping is not a concern.

GALL AMP XI.M12, states that for low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A or other steels with $\leq$ 0.5 wt. % Mo), only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. In addition, for high-molybdenum content steels (SA-351 Grades CF3M, CF3MA, and CF8M or other steels with 2.0 to 3.0 wt.% Mo), static-cast steels with >14% ferrite are potentially susceptible to thermal embrittlement.

Updated Final Safety Analysis Report (UFSAR) Table 5.2-2 indicates that the reactor coolant pipe is made of centrifugally-cast SA-351, Grade CF8A and that the reactor coolant fittings are made of SA-351, Grade CR8A. South Texas Project (STP) UFSAR Table 5.2-1 indicates that the 1974 edition through winter 1975 of American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III is applicable for the construction of the reactor coolant pipe. The staff noted that the centrifugally-cast SA-351, Grade CF8A is not susceptible to thermal aging embrittlement in accordance with the guidance in the GALL Report.

Issue:

For the reactor coolant fittings, neither the GALL Report nor the 1974 edition of ASME Code Section II, Part A, Specification SA-351 identifies "Grade CR8A" as a material grade for fabrication of Code Class CASS components. Therefore, the staff needs additional information regarding the SA-351 material grade that was used to fabricate the static-cast reactor coolant fittings, and the molybdenum and ferrite contents for this material, to determine the material's susceptibility to thermal aging embrittlement.

Request:

- Clarify whether the reference in UFSAR Table 5.2-2 to SA-351, CR8A is accurate and refers to an actual material.

- If the reference to SA-351, CR8A in UFSAR Table 5.2-2 is correct, provide the information on the molybdenum and ferrite contents of the static-cast SA-351 "Grade CR8A" material. In addition, justify why this static-cast stainless steel is not susceptible to loss of fracture toughness due to thermal aging embrittlement. If the material is susceptible to loss of fracture toughness, propose an aging management program to adequately manage this aging effect.

- If the reference to SA-351, CR8A in UFSAR Table 5.2-2 is not correct, identify the correct material grade in SA-351 that represents the actual material for the fittings and provide the information on the molybdenum and ferrite contents of this material. In addition, justify why this material is not susceptible to loss of fracture toughness due to thermal aging embrittlement. If the material is susceptible to loss of facture toughness, propose an aging management program to adequately manage this aging effect.

STPNOC Response:

- The certified material test reports (CMTR) for the reactor coolant fittings show that the fittings were fabricated to the SA-351 Grade CF8A standard. UFSAR Table 5.2.2 will be revised to show the material of the reactor coolant system fittings as SA-351 Grade CF8A.

- A screening, performed in accordance with GALL Rev 2 Section XI.M12 for STP Class 1 CASS fittings, found that the reactor coolant fittings fabricated to the SA-351 Grade CF8A standard are not susceptible to thermal aging embrittlement. The screening evaluated the fittings in accordance with the criteria for statically cast CASS components with low molybdenum content . The GALL considers CASS components with these properties, that have a delta ferrite content > 20 percent, to be potentially susceptible to thermal aging embrittlement. The Hulls equivalent factor was used to calculate delta ferrite content of Class I fittings using chemistry data from CMTRs. The screening calculation found that the delta ferrite content of the fittings to be < 20 percent, and accordingly the fittings are not considered susceptible to a loss of fracture toughness due to thermal aging embrittlement.

Flow-Accelerated Corrosion (018)

RAI 3.4.2.6-1

Background:

The LRA states that the Flow Accelerated Corrosion (FAC) Program implements the Electric Power Research Institute (EPRI) guidelines in NSAC-202L-R3 to detect, measure, monitor, predict, and mitigate component wall thinning. The guidance in NSAC-202L states that systems with low operating times may be excluded from further evaluation. However, NSAC-202L also cautions that some lines that operate less than 2 percent of the time have experienced damage caused by FAC and that these lines should be excluded only if no wear has been observed.

Issue:

South Texas Project Condition Records CR 05-6563 and CR 07-5543 indicate that wall thinning due to FAC was identified within components of the auxiliary feedwater system. However, the aging management review results in Table 3.4.2-6 for the auxiliary feedwater system do not include piping components being managed by the FAC Program.

Request:

Provide technical information that supports the omission of piping and piping components in the auxiliary feedwater system from coverage by the FAC Program.

If it is determined that the FAC Program is an applicable AMP for the auxiliary feedwater system, then provide information regarding actions to ensure that plant-specific operating experience has been considered in all other systems where flow accelerated corrosion has been identified.

STPNOC Response:

Components in the auxiliary feedwater system were identified in the STP flow accelerated corrosion (FAC) System Susceptibility Evaluation as not susceptible to FAC due to infrequent operation. However, wear has been noted in some auxiliary feedwater system components, and these are included in the STP FAC System Susceptibility Evaluation.

A review was conducted to determine whether other systems in the scope of license renewal should be included in the Flow-Accelerated Corrosion program. This review identified six systems in the scope of license renewal subject to wall thinning due to erosion-corrosion that are being managed by the STP Flow-Accelerated Corrosion program.

The turbine vents and drains system was identified as susceptible to FAC in LRA Table 3.3.2-27 but, was not included in the LRA Basis Document XI.M17, Flow-Accelerated Corrosion.

The other five systems: (1) chill water HVAC system, (2) the condensate polisher system (which was evaluated with the condensate system), (3) the makeup water demineralizer system, (4) spent fuel pool cooling and cleanup system, and (5) open loop auxiliary cooling system, were not identified in the LRA as subject to wall thinning or being managed by the Flow-Accelerated Corrosion program (B2.1.6).

The following changes will be made to the LRA to add these systems.

Auxiliary feedwater system: LRA Table 3.4.2-6 and Section 3.4.2.1.6 will be revised to add a line identifying carbon steel piping with an internal environment of secondary water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Turbine vents and drains system: No change is needed for the LRA. The aging effects of this system are included in Table 3.3.2-27, "Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)", which includes a line for carbon steel piping with an internal environment of secondary water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Chill water HVAC system: LRA Table 3.3.2-9 and Section 3.3.2.1.9 will be revised to add a line identifying carbon steel piping with an internal environment of closed cycle cooling water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Condensate polisher system (condensate system): No change is needed for the LRA. The aging effects of this system are included in Table 3.3.2-27, "Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)", which includes a line for carbon steel piping with an internal environment of secondary water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Makeup water demineralizer system: LRA Table 3.4.2-4 and Section 3.4.2.1.4 will be revised to add a line identifying stainless steel piping with an internal environment of demineralized water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Spent fuel pool cooling and cleanup system: LRA Table 3.3.2-2 and Section 3.3.2.1.2 will be revised to add a line identifying stainless steel piping with an internal environment of treated borated water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

Open loop auxiliary cooling system: LRA Table 3.3.2-27 will be revised to add a line identifying carbon steel piping with an internal environment of raw water and an aging effect of wall thinning managed by the Flow-Accelerated Corrosion program (B2.1.6).

LRA Appendix A1.6 and Appendix B2.1.6 will be revised to indicate that the Flow-Accelerated Corrosion program (B2.1.6) manages wall thinning due to other causes, such as erosion/corrosion, in addition to flow-accelerated corrosion.

The LRA Basis Document XI.M17, Flow-Accelerated Corrosion, will be revised to add the following systems to the list of systems managed by the FAC program.

- Auxiliary feedwater system
- Turbine vents and drains system
- Chill water HVAC system
- Condensate polisher system (condensate system)

- Makeup water demineralizer system
- Spent fuel pool cooling and cleanup system
- Open loop auxiliary cooling system.

Enclosure 2 provides the line-in/line-out for LRA Sections 3.3.2.1.2, 3.3.2.1.9, 3.4.2.1.4, 3.4.2.1.6, LRA Tables 3.3.2-2, 3.3.2-9, 3.3.2-27, 3.4.2-4, 3.4.2-6 , and LRA Appendices A1.6 and B2.1.6.

Bolting Integrity (019)

RAI 3.2.2.1-1

Background:

The GALL Report, Table IV.C2, recommends that stainless steel closure bolting in an environment of air with reactor coolant leakage be managed by the Bolting Integrity AMP for loss of preload and cracking aging effects. LRA Tables 3.2.2-1, 3.2.2-4, 3.3.2-8, 3.3.2-19, 3.3.2-22, 3.3.2-23, and 3.3.2-27 state that stainless steel closure bolting with borated water leakage is managed by the Bolting Integrity AMP for the loss of preload aging effect only.

Issue:

It is not clear to the staff why the applicant does not consider cracking to be an aging effect of stainless steel closure bolting in an environment of air with borated water leakage.

Request:

Provide additional information showing why stainless steel closure bolting with borated water leakage does not need to be managed for the aging effect of cracking, or provide information showing that the aging effect of cracking is being managed for this component, material, and environment combination.

STPNOC Response:

The GALL Report, Section IX.D states that the temperature threshold for stress corrosion cracking of stainless steel is 140°F. The stainless steel closure bolting listed in LRA Tables 3.2.2-1, 3.2.2-4, 3.3.2-8, 3.3.2-19, 3.3.2-22, 3.3.2-23, and 3.3.2-27 are in environments where the ambient temperature is less than 140°F. Therefore, cracking is not applicable as an aging effect.

RAI 3.3.2.13-1

Background:

The GALL Report, Table VII.I, recommends that carbon steel closure bolting in an air-indoor uncontrolled (external) environment should be managed by the Bolting Integrity AMP for loss of preload and loss of material aging effects. LRA Tables 3.3.2-13, and 3.3.2-15 state that carbon steel closure bolting with a plant indoor air environment is managed by the Bolting Integrity AMP for the loss of material aging effect. A plant-specific note 1 is added to the LRA table line items which states that, "Loss of preload is conservatively considered to be applicable for all closure bolting."

Issue:

Without specific LRA table line items that address the loss of preload associated with closure bolting, it is not clear to the staff that the plant-specific note 1, alone, provides a sufficient emphasis on the need to manage the loss of preload aging effect for carbon steel closure bolting with a plant indoor air environment under the Bolting Integrity program.

Request:

Provide a line item(s), as appropriate, indicating that the aging effect of loss of preload is being managed for this component, material, and environment combination or provide a justification for not including such line items.

STPNOC Response:

LRA Sections 3.3.2.1.13 and 3.3.2.1.15 and Tables 3.3.2-13 and 3.3.2-15 will be revised to add loss of preload aging effect for carbon steel closure bolting in a plant indoor air (external) environment management by aging management program B2.1.7, Bolting Integrity Program.

Enclosure 2 provides the line-in/line-out changes for LRA Sections 3.3.2.1.13 and 3.3.2.1.15, and LRA Tables 3.3.2-13 and 3.3.2-15

RAI 3.5.2.11-1

Background:

The GALL Report, Table III.B1, recommends that high strength structural bolting made of low alloy steel in an air-indoor uncontrolled environment should be managed by the Bolting Integrity AMP for the cracking aging effect. Additionally, Table III.B1 recommends that structural bolting of *any material* in *any environment* should be managed for the loss of preload aging effect. LRA Table 3.5.2-11 states that high strength structural bolting made of low alloy steel in a plant indoor air environment is managed by the Bolting Integrity AMP for the cracking aging effect but does not address management of the loss of preload aging effect.

Issue:

It is not clear to the staff that the loss of preload aging effect is being managed for the high strength structural bolting components in table 3.5.2-11.

Request:

Provide a line item(s), as appropriate, indicating that the aging effect of loss of preload is being managed for this component, material, and environment combination or provide a justification for not including such line items.

STPNOC Response:

LRA Section 3.5.2.1.11 and Table 3.5.2-11 will be revised to add a line item for managing high strength structural bolting for the aging effect of Loss of Preload.

Enclosure 2 provides the line-in/line-out changes for LRA Section 3.5.2.1.11 and LRA Table 3.5.2-11.

Open-Cycle Cooling Water (021A)

RAI B.2.1.9-2

Background:

During the system walkdown for the AMP Audit, the staff noted the presence of significant cavitation associated with the throttle valve downstream of the essential cooling water (ECW) return line for the component cooling water heat exchanger. Although not specifically discussed in the LRA, during its reviews of operating experience, the staff noted that this issue was documented in Licensee Event Report 499/2005004 (July 11, 2005) and was briefly discussed in the AMP basis document for the Open-Cycle Cooling Water Program. In addition, the AMP basis document discussed erosion-corrosion downstream of another throttle valve, as identified in CR 06-3132, which apparently resulted in the development of an "Erosion Monitoring Program," for the ECW system (see CR 07-14291). Also, as part of the AMP Audit, keyword searches of plant-specific corrective action documents identified additional condition records associated with the ECW system, with the search terms "erosion" and "cavitat," (e.g., CR 05-9516 and CR 06-16228), which appear to pertain to similar cavitation issues.

Issue:

Although LRA Section B2.1.9, "Open Cycle Cooling Water System," states that plant-specific operating experience identified erosion corrosion, no further details are discussed in the LRA. The Open Cycle Cooling Water Program basis document uses the terms erosion and erosion-corrosion; but it was not clear to the staff to which aging mechanism(s) these terms applied, nor how loss of material due to the associated mechanism(s) will be managed in the period of extended operation. Since the identified cavitation erosion has apparently not been corrected, the applicant has chosen to manage the resulting loss of material caused by this erosion mechanism. It is the staff's view that GALL AMP XI.M20, "Open Cycle Cooling Water," only considers solid particle erosion; therefore, applicants that identify and choose to manage a different form of erosion should describe and explain this enhancement to the AMP.

Request:

1) Clarify how the Open-Cycle Cooling Water System Program manages the loss of material due to erosion corrosion resulting from the cavitation issues found in the Operating

Experience review. If loss of material due to erosion corrosion is not being managed by this AMP, indicate which AMP will properly manage this aging effect and by what means it will be managed.

2) Provide details of the "Erosion Monitoring Program" for the ECW system that apparently resulted from plant operating experience in CR 06-3132 or similar CRs. Include a description of the methodology used to identify other locations in the ECW system for erosion monitoring.

3) Describe the extent of condition reviews performed to evaluate whether other systems' components within the scope of license renewal have comparable cavitation issues and discuss the results of these reviews.

STPNOC Response:

1) Erosion/corrosion is managed by the Open-Cycle Cooling Water System program (B2.1.9). General system inspections of the essential cooling water (ECW) system include inspections for erosion and corrosion. Various points in the ECW system are monitored for wall thickness. The inspection points were selected based on experience with erosion/corrosion, safety significance, and flow conditions. The initial inspections were determined based on scheduled maintenance and maintenance history, with subsequent frequencies based on inspection results.

2) Development of the erosion/corrosion monitoring plan was an action taken in response to CR 06-3132. The purpose of the monitoring plan is to identify and perform thickness measurements on components most susceptible to erosion/corrosion. The monitoring plan includes a database that tracks components, thickness measurements, remaining life, and component history. Ultrasonic testing and radiography are methodologies used to measure wall thickness. The monitoring plan database includes a list of locations where wall thickness measurements have been completed, the schedule for re-inspections, and the schedule for new locations to be inspected. New locations are selected based on experience with erosion/corrosion, safety significance, and flow conditions.

3) CR 06-3132 identified erosion discovered downstream of an ECW valve which had seat leakage and was repaired. The extent of condition review identified the corresponding valves in the other ECW trains as likely locations for erosion to occur as well as all the other throttle valves in the ECW system. Additional locations were selected for monitoring based on guidance from EPRI 1010059, Service Water Piping Guideline. For these locations, consideration was given to flow rates, line geometries, and previous wall thickness measurements. Locations in other systems were not evaluated because the unique material/environment combination of the ECW system is not found in the other systems and erosion has not been found in other systems.

RAI B.2.1.9-3

Background:

LRA Section B2.1.9 states that the program includes surveillance and control techniques to manage aging effects caused by protective coating failures in components of the ECW system. The GALL Report defines one category of fouling as macrofouling due to peeled coatings and debris. During its review of operating experience, in CR 07-16847, the staff noted that the inspections of the diesel generator turbocharger intercooler found partial and full tube blockage with foreign material that was "consistent with erosion/corrosion of the coatings" used for the intercooler ribs. In addition, CR 10-12875 identified coating debris that caused blockage on the inside of the essential chiller endbell. Both condition records pertain to potential reduction of heat transfer due to fouling caused by protective coating failures.

Issue:

The LRA neither describes the protective coatings used in the ECW system nor discusses site-specific operating experience associated with protective coating failures to provide objective evidence supporting the conclusion that the effects of aging will be adequately managed during the period of extended operation.

Request:

Provide the bases showing that the surveillance and control techniques will adequately manage fouling of in-scope heat exchangers caused by protective coating failures. Include information to show that the size and amount of debris, which could potentially result from protective coating failures, will not affect intended functions of these downstream components.

STPNOC Response:

Certain components in the Essential Cooling Water (ECW) System are coated to protect the underlying metal surfaces from being exposed to the erosive or corrosive effects of the open-cycle cooling water. The three types of coatings are Belzona, Plasticap 400 Epoxy Phenolic, and coal tar epoxy. The essential chiller condenser, lube oil cooler, jacket water cooler, and intercooler water boxes are coated with Belzona 1321 (Belzona 1391 has also been approved for the diesel generator coolers). Interconnecting piping for the intercoolers is lined with Plasticap 400 Epoxy Phenolic. The ECW Intake bay traveling screens are coated with coal tar epoxy. The ECW Pumps are coated with Belzona 1341. Belzona 1341 has also been applied to eroded surfaces of the ECW pump discharge piping 30x24 inch reducer. The piping near the Component Cooling Water (CCW) System heat exchanger ECW return throttle valves is coated with Belzona 2141 and the valves are coated with Belzona 1341.

General system inspections are performed for macroscopic fouling, biofouling, sediment, corrosion, erosion, pitting, crevice corrosion, and coating failure such as cracks, holes or blister. Various preventive maintenance activities also provide for inspection of protective coatings. The acceptance criteria for coatings are that no erosion, corrosion, flaking or peeling of the coatings is observed. Coatings not meeting these criteria are considered degraded and a condition report (CR) is initiated to document and resolve the concern.

The CCW heat exchangers are periodically performance-tested to verify their heat transfer capabilities. The CCW heat exchangers are inspected and cleaned on demand based on performance test results. The other safety-related heat exchangers cooled by the ECW System are periodically inspected and cleaned if required.

Although STP has experienced erosion of coatings in the ECW system, no sheeting-type coating failures have been observed. In 2007, foreign material was found in one of the intercoolers (CR 07-16847). The engineering evaluation determined that some of the foreign material was consistent with erosion of the Belzona coating used for the intercooler ribs. The majority of the particles were smaller than the 3/8-inch tube diameter. The foreign material did not affect the ability of the intercoolers to perform their design function.

CR 10-12875 and CR 10-12573 documented plugging of the essential chiller ECW drain valve. The material plugging the valve appeared to be Belzona coating. Enough of the material was removed to allow the chiller to be drained, but additional material was inside the endbell. Removal of the remaining material requires removal of the chiller endbell. Removal of the remaining material is scheduled for 2012. There is no impact on the chiller performance.

In a search of plant condition reports, two other cases were found documenting debris from coating failure. CR 05-8601 documented removal of Belzona from downstream of valve EW0101, the CCW heat exchanger ECW return throttle valve in Unit 1. The debris had no impact on the ECW system, and that was most likely transported to the ECW pond or deposited in the piping downstream of the throttle valve. CR 11-1218 addressed pieces of Belzona found in the ends of some tubes in Reactor Containment Building chiller 11B. CR 11-1218 concluded that there have been no performance issues with the chiller.

Continued implementation of the Open-Cycle Cooling Water System program (B2.1.9) and the tracking of plant operating experience provide reasonable assurance that any fouling of in-scope heat exchangers caused by protective coating failures will be adequately managed and not affect the intended functions of the ECW System heat exchangers.

RAI B.2.1.9-4

Background:

During its review of the program basis document for the open cycle cooling water system, the staff noted that coatings are applied to "mitigate cavitation and erosion damage" in the piping and valve body near the essential cooling water return throttle valves, and that these coatings are inspected during preventive maintenance activities approximately every 4 years. During its review of site-specific operating experience, in CR 07-8194, the staff noted that after approximately 2 years, the cavitation-resistant coatings were no longer present in the pipe and valve "cavitation impingement areas," and pipe metal wall loss was noted.

In addition, the AMP basis document states that, although the coatings protect the underlying metal surfaces from being exposed to the raw water environment, the coatings are not credited in aging management to protect metal surfaces.

Issue:

The staff questioned the adequacy of the approximately 4-year inspection frequency for the coatings cited in the AMP basis document. In addition, since the coatings were applied to mitigate cavitation damage, it was unclear that the coatings were not being credited to prevent loss of material in this program. For the coatings to not be credited for aging management, documentation should show that the components, without the protective coatings, will meet current licensing basis with the worst case loss of material which could occur between inspections.

Request:

1) Provide the technical bases that were used to justify the preventive maintenance inspection frequency of approximately 4 years, given that the cavitation-resistant coatings were apparently eroded away in less than 2 years. Include information demonstrating that the worst case operational parameters which affect cavitation severity and duration were considered.

2) Provide the technical bases to show that, without protective coatings, the loss of material due to worst case cavitation erosion will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis.

STPNOC Response:

1) The essential cooling water piping is subject to loss of material or wall thinning due to erosion/corrosion, cavitation, and other mechanisms. Various points are monitored for wall thickness, with the particular inspection points chosen based on past inspection results, safety significance, and flow conditions. These points are monitored at a frequency sufficient to ensure the piping will continue to perform its intended function. Coatings are used in some locations in the essential cooling water piping to mitigate the loss of material or wall thinning to extend the life of the piping. The inspection frequencies for the coatings were established based on maintenance history. It is acceptable if the coatings erode away between inspections because the piping inspections ensure that the piping is repaired or replaced before it reaches the minimum allowable wall thickness.

2) Components are selected for inspection based on consequence of failure, past inspection results, and the relative susceptibility to wall thinning due to erosion/corrosion, cavitation, and other mechanisms. Wear rate is calculated from the measurement of wear and the previous inspection results, which is then used with conservatisms to calculate the lifetime of the component. If the wall thickness is calculated to reach the minimum allowable wall thickness prior to the next scheduled inspection, the component will be repaired or replaced, or the next inspection will be rescheduled. This inspection program ensures that the components will maintain their intended functions consistent with the current licensing basis.

Open-Cycle Cooling Water (021 B)

RAI 3.2.1.15-1

Background:

The GALL Report states that stainless steel containment isolation piping and components in the engineered safety features system exposed to raw water should be managed for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion by the Open-Cycle Cooling Water System Program. The GALL Report states that these components should also be managed for fouling that leads to corrosion by the Open-Cycle Cooling Water System Program. In the LRA items 3.2.1.15 and 3.2.1.35, the applicant has stated that the containment isolation piping and components in the engineered safety features system were evaluated in the systems in which the components were found to have the function of containment integrity.

Issue:

It was not clear to the staff where in the LRA the stainless steel containment isolation piping and components exposed to raw water are identified. In addition, it was not clear how the aging of containment isolation piping and components exposed to water will be managed.

Request:

Provide additional information for which systems the containment isolation piping and components were found to have the function of containment integrity. Provide additional information on what aging management program will be used to manage aging of these components exposed to raw water and provide technical information that supports the adequacy of this program.

STPNOC Response

The only containment penetrations with an internal environment of raw water are in the fire protection system and the radioactive vents and drains system.

The fire protection piping associated with the containment penetration is carbon steel (galvanized). The fire protection containment isolation valves inside containment are carbon steel, and the containment isolation valves outside containment are stainless steel. These components are included in LRA Table 3.3.2-17. The aging management program selected for these components is B2.1.13, Fire Water System. This program requires volumetric or internal inspections of a representative sample of piping components.

The radioactive vents and drains piping associated with the containment penetration is stainless steel. The containment isolation valve inside containment is stainless steel and the containment isolation valve outside containment is cast austenitic stainless steel. These components are included in LRA Table 3.3.2-23. The aging management program selected for these components is B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components. This program requires visual inspections of the internal surfaces of a sample of the components. The locations and intervals for the inspections are based on assessments of the likelihood of significant aging effects as determined from industry and plant operating experience.

These inspections described above will detect loss of material and ensure that the aging effects are managed.

RAI 3.3.1.76-1

Background:

The GALL Report states that steel (with coating or lining) piping, piping components, and piping elements exposed to raw water should be managed for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion by the Open-Cycle Cooling Water System Program. The GALL Report states that these components should also be managed for fouling that leads to corrosion by the Open-Cycle Cooling Water System Program. The Open-Cycle Cooling Water System Program typically uses chemical treatment for biological fouling or flushing in addition to periodic inspections. LRA Table 3.3.2-27 states that carbon steel piping exposed to raw water being managed for loss of material will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

Issue:

It is unclear to the staff how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which only conducts visual inspection activities, is adequate to manage loss of material for the carbon steel piping exposed to raw water in the miscellaneous systems.

Request:

Justify using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of material for the carbon steel piping exposed to raw water in the miscellaneous systems. Provide additional information on why chemical treatments or flushing is not required for these components.

STPNOC Response:

The systems in LRA Table 3.3.2-27 that have carbon steel piping with an internal environment of raw water are the essential cooling pond makeup system and the open loop auxiliary cooling water system

LRA Section 2.3.3.27 states that the essential cooling pond makeup system and the open loop auxiliary cooling water system are non-safety related and perform no safety functions. These systems are within the scope of license renewal based on Criterion 10 CFR 54.4(a)(2) for spatial interaction and do not provide cooling to any safety-related systems. Therefore, loss of heat transfer is not an applicable aging effect requiring management. The only aging effect requiring management is loss of material.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22) manages loss of material. Therefore, this program is considered appropriate to manage the aging of the carbon steel piping with an internal environment of raw water for the essential cooling pond makeup system and the open loop auxiliary cooling water system.

RAI 3.3.2.6-1

Background:

Various types of titanium alloys exposed to raw water with chloride levels greater than several hundred ppm at high temperature can undergo loss of material due to crevice corrosion. The LRA Tables 3.3.2-6, 3.3.2-9, and 3.3.2-20 indicate that titanium heat exchangers are exposed to raw water and may be subject to reduction of heat transfer.

Issue:

It is not clear to the staff that the titanium alloy referenced in the LRA is resistant to crevice corrosion in the specific raw water environments addressed by the LRA AMP.

Request:

Provide additional information on what type of titanium alloys are used in the heat exchangers exposed to raw water and why aging management of loss of material due to crevice corrosion is not included.

STPNOC Response:

The titanium heat exchanger tubes exposed to raw water meet ASME SB-338, Grade 2 (unalloyed titanium). As noted in the Metals Handbook, Volume 13: Corrosion, crevice corrosion in titanium and titanium alloys requires elevated temperatures (>160°F). These heat exchangers are all cooled by the essential cooling water system. The maximum outlet temperature during normal operation in the essential cooling water system is 110°F. Therefore, the titanium tubes in the heat exchangers are not subject to crevice corrosion.

One-Time Inspection (033)

RAI B2.1.16-3

Background:

The GALL Report, Section XI.M32, "One-Time Inspection," "detection of aging effects" program element states that where practical, a representative sample size is 20% of the population or a maximum of 25 components for components managed by both the One-Time Inspection program and AMP XI.M2, "Water Chemistry;" AMP XI.M30, "Fuel Oil Chemistry;" and AMP XI.M39, "Lubricating Oil Analysis" programs. In lieu of using the recommended sample size, the GALL Report states that a technical justification of the sample size used for selecting components for one-time inspection should be included as part of the program's documentation.

LRA Section B.2.1.16, as amended on June 16, 2011, states the One-Time Inspection Program's sample size is based on groups sharing the same material, environment, and aging effects. The LRA also states that the components included in the sample size will be the most susceptible to degradation based on a review of environment, condition, and operating experience.

Issue:

The sample size stated in LRA Section B.2.1.16 is not consistent with the GALL Report recommendations and does not include a technical justification for this deviation from the GALL Report.

Request:

Revise LRA Section B.2.1.16 to reflect the GALL Report recommended representative sample size or provide a technical justification supporting the sample size currently stated in the LRA.

STPNOC Response:

LRA Appendix B2.1.16 and LRA Basis Document XI.M32 (B2.1.16), One-Time Inspection program, will be revised to state that for each material/environment population, a representative sample size is selected of 20 percent of the population up to a maximum of 25 components. The components making up the sample are those determined to be most susceptible to degradation based on a review of environment condition and operating experience. See RAI B2.1.16-2 for change to LRA Appendix A1.16.

Enclosure 2 provides the line-in/line-out revision to Appendix B2.1.16.

Metal Fatigue (060)

RAI 4.3-1

Background:

LRA Table 4.3-2 indicates the current cycle count for Transient 41 for Unit 1 (Charging Trip with Prompt Return to Service) is 10 as of the end of 2008.

Issue:

During its audit, the staff reviewed the applicant's design basis documents and noted that the current cycle count for Transient 41 for Unit 1 was 11 as of April 2005.

Request:

Justify the discrepancy; provide the correct current cycle count and the 60-year projected cycles for Transient 41 for Unit 1.

STPNOC Response:

The South Texas Project (STP) corrective action document that noted 11 Loss of Charging (also known as Charging Flow Shutoff with Prompt Return to Service) events had been initiated based on an April 12, 2005 event in which letdown was temporarily reduced. On further review of plant data recordings, while developing the baseline cycles for license renewal (LRA Table 4.3-2), the April 12, 2005 event was determined not to have been a Loss of Charging event. While the flow rate varied during the day, charging flow remained above 35 gpm for the entire day. The correct current cycle count as of the end of 2008 is 10.

The perturbations of charging flow observed on April 12, 2005 were characteristic of the Charging Flow Step Decrease and Return to Normal transient, which assumes 24,000 occurrences for the design number of cycles. This event is not specifically counted by the Fatigue Monitoring Program because the assumed cycles (24,000) are far greater than the number expected over 60 years.

RAI 4.3-2

Background:

LRA Section 4.3.2.10 states that the TLAAs for Class 1 High Energy Line Break (HELB) locations are dispositioned in accordance with 10 CFR 54.21 (c)(1)(iii), and that the effects of fatigue on the HELB locations will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation.

The staff noted that a CUF value less than 0.1 is one criterion for HELB location selection that is discussed in UFSAR Section 3.6.2.1.1. The staff also noted that, for the pressurizer surge line and accumulator safety injection lines, the applicant uses a criterion of 0.4 instead of 0.1 for the cumulative usage factor (CUF) value. In addition, a CUF value less than 1.0 is a cumulative fatigue damage design criteria in ASME Code Section III.

Issue:

The staff noted that it may be possible that the design cycle limit applicable to HELB piping locations can be less than the "UFSAR Design Cycles" and "Program Limiting Value" identified in LRA Table 4.3-2. In addition, the "acceptance criteria" program element in the Metal Fatigue of Reactor Coolant Pressure Boundary Program did not address how the acceptance criteria will be different for HELB and cumulative fatigue damage.

The Metal Fatigue of Reactor Coolant Pressure Boundary Program indicates that, when the accumulated cycles approach the design cycles, corrective actions will be taken to ensure the analyzed number of cycles is not exceeded; however, it is not clear to the staff if the applicant's program addresses the situation when the accumulated cycles approach the limit in the HELB analyses.

Request:

- Identify the ASME Code Class 1 piping locations discussed in UFSAR Section 3.6.2.1.1 that are within the scope of LRA Section 4.3.2.10. For each location identified, provide the applicable design-basis transients and associated cycle limits.

- Justify that the Metal Fatigue of Reactor Coolant Pressure Boundary Program can adequately ensure the CUF for HELB locations remain below 0.1 (or 0.4 for the pressurizer surge line and the accumulator safety injection line) by using systematic counting of plant transient cycles associated with the HELB analysis. Provide any appropriate revisions to the program elements of the Metal Fatigue of Reactor Coolant Pressure Boundary Program to incorporate activities for ensuring that the CUF for HELB locations remain below 0.1 (or 0.4 for the pressurizer surge line and the accumulator safety injection line).

STPNOC Response:

All piping ASME Code Class 1 piping locations are within the scope of LRA Section 4.3.2.10 except the Reactor Coolant Loops, which were excluded based on the leak-before-break analysis discussed in LRA Section 4.3.2.11. The fatigue analyses which support the determination of the HELB location are discussed in Section 4.3.2.7. The specific HELB locations are identified in UFSAR Table 3.6.2-1 and Figure 3.6.1-1.

The transients used in the fatigue analyses to determine the break locations are listed in the table below. Most of these transients are already considered in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. Some transients in this table are less than the program limiting values presented in LRA Table 4.3-2. LRA Table 4.3-2 will be revised to include these lower values to ensure that corrective actions will be taken for the respective components prior to reaching these lower values. The following transients are included in the table below, but are not included in Metal Fatigue of Reactor Coolant Pressure Boundary Program:

- The "Reduce Temperature Return to Power" transient was included in pressurizer surge line and spray line fatigue analyses. This transient is designed to improve capabilities of the plant during load follow operations. STP does not practice load follow operations; therefore this transient, while included in the fatigue analysis, is not applicable to STP operation. Therefore, this transient is not counted in the program.

- The "Charging Flow 50% Decrease and Return" and "Letdown Flow 50% Increase and Return" transients were included in the normal and alternate charging line fatigue analyses. These transients are designed to compensate for reactor coolant system (RCS) volume changes resulting from changes in reactor power. The number of transients is based on load follow operations. STP does not practice load follow operations. Therefore, this transient is not counted in the program.

- The "Letdown Flow 50% Decrease and Return" transient was included in normal and alternate charging line fatigue analyses. It is not a normal operating event with the plant at power. However, this transient was included for conservatism and assumed to occur approximately once a week for 40 years. The number experienced will not approach the limit given the conservatism of this assumption. Therefore, this transient is not counted in the program.

- The "Injection Flow Temperature Change" was included in reactor coolant pump (RCP) seal injection line fatigue analyses. As discussed in LRA Section 4.3.2.3, this transient will occur when the charging pump suction is switched back and forth from the volume control tank to the refueling water storage tank. STP does not normally operate in this manner.

In addition, an inadvertent switching of charging pump suction sources due to equipment failure has not occurred to date. This history demonstrates that the number of transient events used should not be reached and the subsequent results of the fatigue analysis are valid for the period of extended operation. Therefore, this transient is not counted in the program.

- The "Loss of Seal Injection Flow" transient was included in RCP seal injection line fatigue analyses. The transient is assumed to occur 40 times over plant life. "Loss of Seal Injection Flow" occurs whenever charging is lost. There are two types of loss of charging transients and each is monitored to a 20 event limit. Therefore, the "Loss of Seal Injection Flow" transient is managed for the period of extended operation by counting the loss of charging events and is not monitored as a separate transient in the program.

- The "Accumulator Check Valve Testing" transient is assumed to occur every refueling. Refueling is monitored; therefore, the "Accumulator Check Valve Testing" transient is managed for the period of extended operation.

Transient Description	UFSAR	Program Limiting Value	Letdwn	Excess Letdwn	Norm/Alt Charge**	RHR-SI	CVCS Seal Wtr Inj	PZR Surge	PZR Safety	RC Drains	PZR Spray
Normal Conditions	-	-	-	-	-	-	-	-	-	-	-
Plant Heatup (RCS) at 100°F/hr	200	200	200	200	200	200	-	200	200	200	-
Plant (RCS) Cooldown at 100°F/hr	200	200	200	200	200	200	-	200	200	200	-
Pressurizer Heatup	--	200	--	--	-	-	-	-	-	-	200 (6 sprays each)
Pressurizer Cooldown	200	200	-	-	-	-	-	-	-	-	200 (3 sprays & 1 aux spray each)
Unit Loading 5%/min (15%-100% Full Power/min)	U1-3,000 U2-10,300	3,000	13,200	13,200	7,920	13,200	-	13,200	13,200	13,200	13,200
Unit Unloading 5%/min (100%-15% Full Power)	U1-3,000 U2-10,300	3,000	13,200	13,200	7,920	13,200	-	13,200	13,200	13,200	13,200
Reduced Temperature Return to Power	-	-	-	-	-	-	-	2,000	2,000	2,000	-
Step Load Increase (10% Full Power)	2,000	1,200	2,000	2,000	**1,200**	2,000	-	2,000	2,000	2,000	2,000
Step Load Decrease (10% Full Power)	2,000	1,200	2,000	2,000	**1,200**	2,000	-	2,000	2,000	2,000	2,000
Large Step Load Decrease (with steam dump)	200	120	200	200	**120**	200	-	200	200	200	200
Steady State Fluctuations (Initial)	1.5E+05	9.0E+04*	1.5E+05	1.5E+05	**9.0E+04**	1.5E+05	-	1.5E+05	1.5E+05	1.5E+05	**1.5E+06**
Steady State Fluctuations (Random)	3.0E+05	1.8E+06*	3.0E+06	3.0E+06	**1.8E+06**	3.0E+06	-	3.0E+06	3.0E+06	3.0E+06	-
Feedwater Cycling (Hot Shutdown)	2,000	1,200	2,000	2,000	**1,200**	2,000	-	2,000	2,000	2,000	2,000
Loop Out of Service, Active Loop (Normal Shutdown)	80	80	80	80	96	80	-	80	80	80	80
Loop Out of Service, Inactive Loop (Normal Startup)	70	70	70	70	84	70	-	70	70	70	-

Transient Description	UFSAR	Program Limiting Value	Letdwn	Excess Letdwn	Norm/Alt Charge**	RHR-SI	CVCS Seal Wtr Inj	PZR Surge	PZR Safety	RC Drains	PZR Spray
Unit Loading (0%-15% Full Power)	500	500	1,490	1,490	894	1,490	-	500	500	1,490	500
Unit Unloading (15%-0% Full Power)	500	500	1,490	1,490	894	1,490	-	500	500	1,490	500
Boron Concentration Equalization	26,400	15,840*	26,400	26,400	**15,840**	-	-	26,400	26,400	26,400	26,400
Refueling	80	80	80	80	80	80	-	80	80	80	80
Primary Side Leak Test	U1-120 U2-200	120	200	200	200	200	**120**	200	200	200	200
Secondary Side Leak Test	80	80	-	-	-	-	-	80	80	-	-
Tube Leak Test	800	800	-	-	-	-	-	800	800	-	-
Turbine Roll Test	20	20	20	20	20	20	-	20	20	20	20
Charging Flow 50% Decrease and Return	-	-	-	-	14,400	-	-	-	-	-	-
Charging Flow 50% Increase and Return	-	14,400	-	-	**14,400**	-	-	-	-	-	-
Letdown Flow 50% Decrease and Return	-	-	-	-	1,200	-	-	-	-	-	-
Letdown Flow 50% Increase and Return	-	-	-	-	14,400	-	-	-	-	-	-
Injection Flow Temperature Change	-	-	-	-	-	-	180	-	-	-	-
Upset Conditions	-	-	-	-	-	-	-	-	-	-	-
Loss of Load (Above 15% Full Power), Without Immediate Turbine or Reactor Trip	80	48	80	80	**48**	80	-	80	80	80	80
Loss of All Offsite Power (With Natural Circulation in the Reactor Coolant System)	40	40	40	40	40	40	-	40	40	40	-

Transient Description	UFSAR	Program Limiting Value	Letdwn	Excess Letdwn	Norm/Alt Charge**	RHR-SI	CVCS Seal Wtr Inj	PZR Surge	PZR Safety	RC Drains	PZR Spray
Partial Loss of Flow, Active Loop (Loss of One RCP)	80	48	80	80	**48**	80	-	80	80	80	80
Reactor Trip from Full Power, without Cooldown.	230	138	230	230	**138**	230	-	230	230	230	-
Reactor Trip from Full Power, with Cooldown, without Safety Injection	160	96	160	160	**96**	160	-	160	160	160	-
Reactor Trip from Full Power, with Cooldown, with Safety Injection	10	10	10	10	10	10	-	10	10	10	-
Inadvertent RCS Depressurization (Resulting in Reactor Trip)	20	20	20	20	20	20	-	20	20	20	-
Inadvertent Auxiliary Spray	10	10	-	-	-	-	-	10	-	-	10
Inadvertent Startup of an Inactive RCS Loop	10	6	10	10	**6**	10	-	10	10	10	10
Control Rod Drop	80	48	80	80	**48**	80	-	80	80	80	-
Inadvertent ECCS Actuation	60	60	60	60	60	60	-	60	60	60	60
Design Basis Earthquake (OBE)	5	5	5	5	5	5	5	5	5	5	5
Excessive Feedwater Flow	30	30	30	30	30	30	-	30	30	30	-
Normal Charging and Letdown Shutoff and Return	-	36	60	-	**36**	-	-	-	-	-	-
Letdown Trip with Prompt Return	-	120	200	-	**120**	-	-	-	-	-	-
Letdown Trip with Delayed Return	-	12	20	-	**12**	-	-	-	-	-	-
Charging Trip with Prompt Return	-	12	-	-	**12**	-	-	-	-	-	-

Transient Description	**UFSAR**	**Program Limiting Value**	**Letdwn**	**Excess Letdwn**	**Norm/Alt Charge****	**RHR-SI**	**CVCS Seal Wtr Inj**	**PZR Surge**	**PZR Safety**	**RC Drains**	**PZR Spray**
Charging Trip with Delayed Return	-	12	20	-	**12**	-	-	-	-	-	-
Loss of Seal Injection Flow	-	-	-	-	-	-	40	-	-	-	-
Test Conditions	-	-	-	-	-	-	-	-	-	-	-
Primary Side Hydrostatic Test	10	1	10	10	10	10	10	-	10	-	10
Accumulator Check Valve Testing	-	-	-	-	-	80	-	-	-	-	-
Auxiliary Conditions	-	-	-	-	-	-	-	-	-	-	-
Plant Cooldown with Accumulator Blowdown	-	4	-	-	-	4	-	-	-		-
High Head Safety Injection	-	30	-	-	-	**30**	-	-	-		-

* *Transient is not counted by the current program however the justification provided in footnotes of LRA Table 4.3-2 and not affected by the reduction in the number of transients provided here.*

** *Some of design transients for the alternate and normal charging nozzles are reduced by 60%. This is based on the rotation between the normal and alternate charging paths, which would result in 50% of the transients being assigned to each path. An addition 10% is added for each path as a conservatism to account for uncertainty in the availability of each path.*

Maintaining the numbers of experienced design transients less than the numbers of analyzed design transients ensures that the actual usage experienced by a location will be less than the analyzed CUF. As the plant approaches the cycle count action limit, the program includes a corrective action to ensure that the analytical bases of the HELB locations are maintained.

Enclosure 2 provides line-in/line-out revision to LRA Table 4.3-2.

RAI 4.3-3

Background:

LRA Section 4.3.2.10 states that the fatigue analysis for the welded attachments to Class 2 and Class 3 piping demonstrate a CUF of less than 1.0 during the period of extended operation. The applicant dispositioned this time-limited aging analysis (TLAA) in accordance with 10 CFR 54.21 (c)(1)(ii), stating that the fatigue analyses that support the elimination of arbitrary intermediate break locations, other than those for the charging system and the main feedwater system, demonstrate a CUF less than 1.0 during the period of extended operation.

Issue:

LRA Section 4.3.2.10 did not provide the 40-year CUF and corresponding 60-year projected CUF values for the integral pipe supports, other than those for the charging system and the main feedwater system, to support the applicant's disposition in accordance with 10 CFR 54.21(c)(1)(ii); therefore, the staff cannot verify the adequacy of the applicant's TLAA disposition.

Request:

Provide the 40-year CUF and corresponding 60-year projected CUF values in the fatigue analysis for those welded attachments to Class 2 and Class 3 piping and justify that it supports the disposition for this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), in that the analyses have been projected to the end of the period of extended operation.

STPNOC Response:

The following are the CUF numbers for the requested locations. The CUFs were projected to 60 years by multiplying the 40 year CUF by 1.5. The results are projected to be below the Code allowable of 1.0 for the period of extended operation. Therefore, TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

- Chemical and Volume Control System – Letdown

  40 year CUF = 0.3704; 60 year CUF = 0.5556

- Auxiliary Feedwater

  40 year CUF = 0.4385; 60 year CUF = 0.65775

- Main Steam

  40 year CUF =0.0985; 60 year CUF = 0.14775

RAI 4.3-4

Background:

LRA Section 4.3.6 describes the fatigue TLAA of ASME Code Section III, metal bellows and expansion joints. The applicant stated that the analyzed numbers of cycles for all but seven of the diesel generator cooling water expansion joints are greater than the specified numbers of cycles extrapolated to 60 years; therefore the analyses are valid for these bellows through the period of extended operation and were dispositioned in accordance with 10 CFR 54.21 (c)(1)(i).

Issue:

- For the diesel generator cooling water expansion joints that are dispositioned in accordance with 10 CFR 54.21(c)(1)(i), the applicant did not provide the number of analyzed cycles and the specified numbers of cycles extrapolated to 60 years to justify this disposition.

- The staff noted that LRA Table 3.3.2-4 provides an aging management review (AMR) line item for nickel alloy expansion joints exposed to raw water and subject to cumulative fatigue damage in the essential cooling water and essential cooling water wash system, which is managed by a TLAA. The staff reviewed LRA Section 4.3 and it was not clear to the staff which specific TLAA is being credited to manage cumulative fatigue damage for this particular AMR line item.

Request:

- Provide the analyzed cycles and the specified number of cycles extrapolated to 60 years for the diesel generator cooling water expansion joints and justify the disposition of this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

- Clarify the fatigue TLAA that is being credited to manage cumulative fatigue damage for the nickel alloy expansion joints identified by the AMR line item in LRA Table 3.3.2-4. If the fatigue TLAA is not discussed in LRA Section 4, justify why the TLAA was not identified and dispositioned in accordance with 10 CFR 54.21 (c)(1). In lieu of a justification, amend the LRA to include the appropriate fatigue TLAAs, including the disposition in accordance with 10 CFR 54.21(c)(1) with sufficient justification that supports this disposition.

STPNOC Response:

- The analyzed and the specified numbers of cycles are presented in the below table. The numbers of specified cycles are extrapolated to 60 years by multiplying the specified value by 1.5. If the number of analyzed cycles is greater than the specified number of cycles projected to 60 years, then the analysis is valid for the period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

- The expansion joints in question are the ECW Pump Expansion Joints, 3R281(2)NJX101(201)A/B/C, which are presented in the below table. LRA Section 4.3.6 and Appendix A3.2.5 will be revised to include the ECW Pump expansion joints identified by the AMR line item in LRA Table 3.3.2-4.

Component ID	Unit	Component Description	Spec. Cycles	Analyzed Cycles	60-year Cycles (Spec x 1.5)	Valid for 60 yrs
3R281(2)NJX101(201)A/B/C	1/2	ECW Pump Expansion Joint	16,000	174,183	24,000	Y
3R281NJX102A/B/C	1	Diesel Generator Expansion Joint	7,000	253,354	10,500	Y
3R282NJX202A/B/C	2	Diesel Generator Expansion Joint	7,000	298,999	10,500	Y
3R281NJX103A/B/C	1	Diesel Generator Expansion Joint	3,000	3,789	4,500	N
3R282NJX203A/B/C	2	Diesel Generator Expansion Joint	3,000	3,565	4,500	N
3R281NJX105A/B/C	1	Diesel Generator Expansion Joint	1,500	2,301	2,250	Y
3R282NJX205A	2	Diesel Generator Expansion Joint	2,500	3,907	3,750	Y
3R282NJX205B	2	Diesel Generator Expansion Joint	4,178	18,222	6,267	Y
3R282NJX205C	2	Diesel Generator Expansion Joint	1,500	2,009	2,250	N
3R281(2)NJX106(206)A/B/C	1/2	Diesel Generator Expansion Joint	7,000	13,032	10,500	Y
3Q151(2)MJX2134 3Q151(2)MJX2234 3Q151(2)MJX2334	1/2	Diesel Generator Expansion Joint	2,000	12,304	3,000	Y

See Enclosure 2 for the revised LRA Section 4.3.6 and Appendix A3.2.5.

RAI 4.3-5

Background:

LRA Section 4.3.2.12 states that, as a result of the replacement steam generator project, the main feedwater control valves were analyzed for a new set of operating design transient conditions, and it was found that they could not be qualified for the full number of loading and unloading transients defined for the life of the plant. To obtain acceptable fatigue limits the number of loadings and unloadings between 15 and 100 percent power had to be reduced from

13,200 to 10,300 for Unit 2. In addition, this limit does not apply to design of the Unit 1 feedwater control valves.

The applicant stated that it had experienced 62 occurrences of this transient for Unit 1 and 43 occurrences for Unit 2 through July 27, 1989, both of which were less than the 385 cycles anticipated at that point in the design life. The applicant projected 3,366 events to occur over 60 years and stated that this demonstrates a large margin between the analyzed value of 10,300; therefore, this TLAA was dispositioned in accordance with 10 CFR 54.21(c)(1)(i), the fatigue analysis for the feedwater control valves is valid for the period of extended operation. The applicant stated that the loading and unloading events are the largest contributor to fatigue in the feedwater control valves, and that all other transients contribute 0.055 to the 40-year CUF.

The staff noted that the Operating License for Unit 1 was issued on March 22, 1988, and on March 28, 1989, for Unit 2. LRA Table 4.3-2 provides the "Program Limiting Value" for the unit loading and unloading transients (Transients NO.5 and No.6) of 3000 for Unit 1 and 10,300 for Unit 2.

Issue:

It is not clear to the staff whether the use of the 16-month (from March, 1988 to July, 1989) data for Unit 1 and 4-month (March 28, 1989 to July 27, 1989) data for Unit 2 to extrapolate the number of occurrences of unit loading and unloading transients for 60 years is conservative. It is also not clear how the applicant determined that 385 cycles of these transients were anticipated to occur through July 27, 1989.

The staff noted that the estimated occurrences of 3,366 cycles for these transients exceeds the "Program Limiting Value" of 3,000, which demonstrates that the applicant's disposition of this TLAA in accordance with 10 CFR 54.21 (c)(1)(i) is not valid. In addition, the staff noted that the CUF contribution to the fatigue in the feedwater control valves by the unit loading and unloading transients was not included in the LRA.

Request:

- Justify that the use of data from initial plant operation to July 1989 for Unit 1 and data from initial plant operation to July 1989 for Unit 2 to estimate the number of occurrences for 60-years is conservative. Describe and justify how the 385 cycles of the unit loading and unloading transients that were anticipated to occur through July 27, 1989 was determined for Unit 1 and 2.

- Justify that the disposition in accordance with 10 CFR 54.21 (c)(1)(i) for the fatigue TLAA of the Unit 1 Class 3 Feedwater Control Valves designed to Class 1 methods is appropriate, when considering the 60-year projected cycles of the unit loading and unloading transient (3,366 cycles) exceeds the "Program Limiting Value" of 3,000 cycles.

- Provide the CUF contribution for the loading and unloading transients on the feedwater control valves.

STPNOC Response:

- The data from initial operation is a conservative estimate of the number of unit loading and unloading occurrences for the 60 year period. The total transient count for Unit 1 and Unit 2 for the early period (62 and 43, respectively) contains multiple initial startup operational transients that are not expected to be repeated during the remainder of plant life. Based on recent operating history, this transient would typically be expected to occur only 1-3 times per 18 month cycle.

  The 385 cycles anticipated to occur during the early operating period were calculated by multiplying the original design basis value of 13,200 cycles (based on a load following plant design) by the fraction of life that the plant had experienced. The STP units are operated as base load plants; therefore, this anticipated number of cycles is a highly conservative estimate.

- The projected cycles for the Unit 1 Class 3 Feedwater Control Valves resulted in a conservative estimate of 3,366 cycles for 60 years of operation. The 3,000 cycle "Program Limiting Value," as noted in UFSAR Table 3.9-8, Footnote 2, pertains only to the Unit 1 BMI Half Nozzle repair. For the Unit 1 Class 3 Feedwater Control Valves, the cycle limiting value remains at 10,300, as described in LRA section 4.3.1.12. Therefore, the conservative estimate of 3,366 cycles remains well below the cycle limiting value for the valves.

- The total CUF is 0.999 of which loading and unloading events contribute 0.944. The other transients contribute 0.055 to the 40-year CUF.

RAI 4.3-6

Background:

LRA Table 4.3-8 indicates that, for the hot leg surge nozzle, the 40-year CUF, the 40-year environmentally-assisted fatigue (EAF) CUF, and the 60-year EAF CUF are 0.8196, 7.5904, and 11.3856 respectively. LRA Table 4.3-8 also indicates that, for the charging system nozzle (normal line and alternate line), the 40-year CUF, 40-year EAF CUF, and 60-year EAF CUF are 0.19814, 1.5585, and 2.3378, respectively.

Issue:

During its audit, the staff found that the CUF and EAF CUF values for these nozzles in the applicant's basis documents are different from those in the LRA Table 4.3-8.

Request:

Revise LRA Table 4.3-8 to provide correct CUF and EAF CUF values that are consistent with the basis documents for the Hot Leg Surge Nozzle and Charging System Nozzles.

Confirm that the remaining information in LRA Table 4.3-8 is accurate. If not, provide the appropriate revisions.

STPNOC Response:

Enclosure 2 provides the line-in/line-out revision to Table 4.3-8 to correct CUF and EAF CUF values for the Hot Leg Surge Nozzle and Charging System Nozzles. These corrected values are consistent with the basis documents. The remainder of the table was reviewed and no other changes were identified.

RAI 4.3-7

Background:

LRA Section 4.3.4 describes three methods that were used to reduce the EAF CUF values: (1) recalculating the CUF with a more accurate fatigue analysis; (2) using projected values of the accumulated number of transient events, instead of using the 40-year number of events; and (3) calculating an average F_{en} using strain-rate dependent F_{en} values for load set pairs significant to fatigue and using the maximum Fen for load set pairs not significant to fatigue.

Issue:

Based on the information in LRA Section 4.3.4, the staff cannot determine what constitutes a "more accurate fatigue analysis," how it was performed and what conservatism was removed to obtain reduced EAF CUF values. The staff also cannot identify the locations in LRA Table 4.3-8 that used these three methods, described above, to reduce conservatism to obtain reduced EAF CUF values.

Request:

- For those locations listed in LRA Table 4.3-8, identify the components and the associated methods described above that were used to reduce the EAF CUF values.
- For each location, describe and justify the techniques used in performing the "more accurate fatigue analysis," and how any conservatism was removed to reduce the EAF CUF.

STPNOC Response:

The following summarizes the justification for each method and the applicable components for which each method was used.

1. The hot leg surge nozzle, the normal and alternate charging nozzles, the RHR inlet nozzle, and the accumulator safety injection nozzle locations are the locations in LRA Table 4.3-8 re-evaluated with “more accurate fatigue analyses.” The “more accurate fatigue analyses” were performed using the NB-3200 method versus the NB-3600 methods from the original Code calculations. NB-3200 fatigue analyses are expected to yield significantly lower fatigue than NB-3600 methods. The analyses also removed excess conservatism with guidance from Section 4.3 of NUREG/CR-6260, which states, in part:

Did fatigue requirements change from the ASME Code edition of record for the design basis calculations to the current Code edition? For example the $\Delta T1$ term was eliminated from the NB-3600 primary plus secondary stress equation (Equation 10) for piping in the 1977 edition, Summer 1979 addenda of the Code. A corresponding change was made to Table NB-3217-2.

The change in Table NB-3217-2 means that, for piping, stresses due to linear radial temperature gradient are reclassified as peak stress. Hence, the linear radial temperature gradient is subtracted from the membrane plus bending component.

2. The hot leg surge nozzle and the normal and alternate charging nozzles are the locations that had EAF CUFs calculated using the 60 year transient projections. NUREG/CR-6260 allows the use of this method for removing conservatism.

3. The hot leg surge nozzle; the normal and alternate charging nozzles; and the accumulator safety injection nozzles are the locations that had EAF CUFs calculated using strain rate dependent F_{en}'s for stainless steel from NUREG-5704. NUREG/CR-6260 allows the use of this method for removing conservatism.

RAI 4.3-8

Background:

LRA Section 4.3.2.1 states that the maximum usage factor based on the design number of transient cycles in the reactor studs is 0.3372, and for the stud hole inserts is 0.8852. The applicant stated that the effects of cumulative fatigue damage will be managed during the period of extended operation using its Metal Fatigue of Reactor Coolant Pressure Boundary Program.

In its review of the applicant's operating experience during the audit, the staff noted that a work order dated April 12, 2007, indicates that an ASME Code Section XI, replacement of the #30 ROTO-LOK stud was conducted in Unit 2 during Refueling Outage 12. The associated design change package, dated April 9, 2007, indicates that Stud #30 of Unit 2 had rotated inadvertently during the de-tensioning process causing it to partially engage inside the stud hole insert, and that this condition caused damage to Stud #30, which was partially engaged. The design change package also indicates that the applicant decided to replace Stud #30 of Unit 2 with a spare stud of the same kind. Based on an evaluation performed on the stud hole insert, the applicant determined that the non-conforming condition of the stud insert was dispositioned as "Use-As-Is." The applicant's design change package further indicates that the damaged areas of the stud hole insert bearing surfaces are conservatively estimated to be 17% of the original area of contact.

Issue:

The staff noted that the reduced load bearing surfaces of the partially damaged (rolled) stud hole insert increases the stress level applied to the studs and the stud hole insert, which may affect assumptions used in the fatigue analyses of the reactor vessel head components. It is not clear to the staff whether the TLAA disposition in accordance with 10 CFR 54.21 (c)(1)(iii) for the reactor vessel closure head studs in LRA Section 4.3.2.1 considered the effect of the damaged stud hole insert.

Request:

Clarify and justify whether the assumptions and results of the fatigue analyses of the reactor vessel head components remain valid, when considering the operating experience related to the stud hole insert described above. In addition, discuss whether the damaged stud hole insert affects the number of analyzed design transients that were determined in the fatigue analyses.

Clarify the fatigue analyses and the associated components that are affected by the damaged stud hole insert and justify that the effect of the cumulative fatigue damage of these components, considering the existence of the damage stud hole insert, will be managed for the period of extended operation.

STPNOC Response:

The damage to the stud hole insert is along only about 17 percent of the length of the lug. The damage is radially inward from the location of the maximum usage factor (at the intersection of the lug and the vertical cylinder surface of the insert) such that the bending moment loading on the lugs is not as great at maximum usage factor location as at the damaged location. Therefore, the increase in stress at the maximum usage factor location would be less than 17 percent. Additionally, the current CUF of 0.8852 was calculated in a very conservative manner. The stress pairing that contributes the most to fatigue was analyzed with 13,177 events when only 10 events were required. This adds about 0.4 to the CUF. Given these factors the reported CUF of 0.8852 is bounding and the damage will not affect the number of analyzed design transients. The Metal Fatigue of Reactor Coolant Pressure Boundary Program will maintain this margin for the original analysis during the period of extended operation by ensuring that the specified 10 events are not exceeded.

The stud nut, washer, and associated collar were not damaged during this event. The damage did not affect any other component other than the damage stud hole insert. The stud was replaced.

RAI 4.3-9

Background:

As described in UFSAR Section 3.9.1.1.8, the small loss-of-coolant accident, small steam line break, and complete loss of flow are system transients and are considered emergency conditions. LRA Sections 4.3.2.7 and A3.2.1.7 state that the TLAA disposition for ASME Code Section III, Class 1 piping and piping nozzles is in accordance with 10 CFR 54.21 (c)(1)(iii). The LRA sections also indicate that the fatigue usage factors in these components do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of normal, upset, and emergency transient events. LRA Sections 4.3.3 and A3.2.2 state that the TLAA disposition for the reactor vessel internals is in accordance with 10 CFR 54.21(c)(1)(iii) and indicate that the fatigue usage factors in these components do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of normal, upset, and emergency transient events. The applicant also stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program described in LRA Section 4.3.1 and B3.1 ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number.

Issue:

LRA Section 4.3.1.1 indicates that the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency and faulted conditions. LRA Table 4.3-2 also does not include the three emergency conditions listed above. It is not clear to the staff: (1) if LRA Table 4.3-2 includes all transients that were used in these fatigue analyses; and (2) whether the three transients identified as emergency conditions, in UFSAR Section 3.9.1.1.8, will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Request:

Clarify whether emergency conditions are included into the fatigue analyses for ASME Code Section III, Class 1 piping and piping nozzles and the reactor vessel internals. If so, justify why the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency transients. If not, clarify why the dispositions for the fatigue analyses of ASME Code Section III, Class 1 piping and piping nozzles and the reactor vessel internals in the aforementioned LRA Sections discuss emergency transients. If necessary, revise the LRA accordingly.

STPNOC Response:

ASME Section III NB-3222.4 requires the inclusion of those transients expected during normal service conditions. Therefore, the emergency conditions noted in the NRC RAI (small loss-of-coolant accident, small steam line break, and complete loss of flow) are not required to be included in the ASME Code Section III Class 1 fatigue analyses. In certain instances, analysts conservatively included emergency transients in the fatigue analyses for ASME Code Section III Class 1 piping lines. Emergency transients would constitute a significant event and would, require initiation of a corrective action document and thorough analysis of the event. Therefore, emergency transients do not need to be monitored in the Reactor Coolant Pressure Boundary Program.

An editorial error was made in Section 4.3.3, "Disposition: Aging Management, 10 CFR 54.21(c)(1)(iii)", during the LRA development. LRA Section 4.3.3 and LRA Appendix A3.3.2 should not discuss the effects of emergency transients. LRA Section 4.3.3 and Appendix A3.3.2 will be revised to state:

> The Subsection NG fatigue usage factors for reactor vessel internals do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of normal and upset transient events.

Enclosure 2 provides a line-in/line-out revision to LRA Section 4.3.3 and LRA Appendix A3.3.2.

RAI 4.3-10

Background:

LRA Section 4.3.4 states that, despite efforts to reduce the EAF CUF below 1.0, the EAF CUFs for the hot leg surge nozzle and charging nozzles are projected to exceed 1.0 within 60 years of operation. Corrective action for these locations will be required under the Metal Fatigue of Reactor Pressure Boundary Program when the cycle-based fatigue (CBF) results, including the effects of the reactor coolant environment, indicate that a fatigue based action limit has been reached. LRA Section 4.3.4 also describes several methods that the applicant took to remove conservatism and reduce the EAF CUF values.

LRA Table 4.3-1 indicates that the stainless steel hot leg surge nozzle (safe end) and charging system nozzle (normal and alternate line) are NUREG/CR-6260 locations that will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program with the CBF monitoring method. LRA Table 4.3-8 provides the 60-Year EAF CUF of 11.3856 for the hot leg surge nozzle (safe end) and 2.3378 for the charging system nozzle (normal and alternate line).

Issue:

In the closure of GSI-190, the staff determined that the risk from fatigue failure of the primary coolant pressure boundary components is very small for a plant life of 40 years; however, since conservatism has already been removed to calculate the 60-year EAF CUF for the hot leg surge nozzle and charging system nozzle, which still exceed the Code design limit of 1.0, it is not clear to the staff how the applicant will manage fatigue with its Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Request:

When considering that conservatism has already been removed to obtain 60-year EAF CUF values for the hot leg surge nozzle and charging system nozzle, which still exceed the Code design limit of 1.0, describe how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage fatigue of these components for the period of extended operation, when considering environmental effects. As part of the explanation, describe the CBF action limits for these components and the corrective actions that may be taken or have been taken.

STPNOC Response:

The normal and alternate charging nozzles EAF CUF is based on the transient severity and the number projected for 60 years. Using current cycle-count, the CBF algorithm in FatiguePro results in an EAF CUF of 0.79 (i.e., 0.1 x 7.866). The charging nozzles can continue to be managed using CBF. When the EAF CUF usage approaches 1.0, additional corrective actions can be taken, such as additional analyses, repair, replacement or implementation of stress-based fatigue monitoring consistent with NRC Regulatory Issue Summary (RIS) 2008-30, "Fatigue Analysis of Nuclear Power Plant Components".

The current cycle-count for the hot leg surge nozzle EAF CUF is greater than 1.0. Corrective action will be taken within two years prior to entering the period of extended operation, consistent with the LRA commitment 30. Similar to the charging nozzles, the corrective actions include re-analysis, repair, or replacement.

RAI 4.3-11

Background:

LRA Section 4.3.1.2 states that the occurrences of the transients listed in LRA Table 4.3-2 are tracked and the CUFs at the locations listed in LRA Table 4.3-1 are managed using either the cycle counting (CC) monitoring method or the cycle-based fatigue (CBF) monitoring method. In addition, it states the most limiting number of cycles for each transient is listed as the "Program Limiting Value" and will be used for the Metal Fatigue of Reactor Coolant Pressure Boundary Program as listed in LRA Table 4.3-2.

LRA Section 4.3.1.3 states that the locations listed in LRA Table 4.3-1, "Summary of CBF Monitored Locations in the STP Fatigue Management Program," will be monitored for fatigue usage using the CBF monitoring method.

LRA Section 4.3.4 states that a method used to reduce the EAF CUF values includes using projected values of the accumulated number of transient events, which are provided in LRA Table 4.3-2, instead of using the 40-year number of events.

Issue:

Based on the information from LRA Sections 4.3.1.2, 4.3.1.3, 4.3.4, and LRA Tables 4.3-1 and 4.3-2, the following is not clear to the staff:

- Are the components identified in LRA Table 4.3-1 monitored by CC, CBF or a combination of the monitoring methods.
- Are the components identified in LRA Table 4.3-1 the only ones monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage cumulative fatigue damage.
- Are there other TLAAs that use the 60-year projected cycles from LRA Table 4.3-2, other than the EAF evaluations, and does the Metal Fatigue of Reactor Coolant Pressure Boundary Program account for the use of these cycles when using the CC monitoring method.

In addition, the staff noted that LRA Table 4.3-1 did not mention several components and their TLAAs (e.g., reactor vessel internals, pressurizer, steam generator, residual heat removal valves) that were dispositioned in accordance with 10 CFR 54.21(c)(1)(iii); therefore it is not clear which monitoring method will be used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage cumulative fatigue damage of these components.

Request:

- Clarify the monitoring method used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage cumulative fatigue damage for the components/locations and their TLAAs discussed in LRA Section 4.3 that were dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). If necessary, provide the appropriate revisions to the LRA.

- If there are any TLAAs that use the 60-year projected cycles other than the EAF evaluations, clarify if the Metal Fatigue of Reactor Coolant Pressure Boundary Program accounts for the use of these cycles in the CC monitoring method. In addition, justify that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will ensure that these TLAAs remain valid and that cumulative fatigue damage will be adequately managed through the period of extended operation.

STPNOC Response:

- Components identified in LRA Table 4.3-1 are monitored by cycle-based fatigue (CBF). All other components that are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) are monitored by cycle counting.

- There are no other fatigue analyses which use the 60-year projected cycles.

RAI 4.3-12

Background:

LRA Section 4.3.1.3 states that the applicant captured all the necessary transient events, and that the event history was taken primarily from existing manual or computer-assisted cycle counting records. In addition, the LRA states that the procedures at the site define the tracking requirements and record the plant cyclic transients.

LRA Section 4.3.1.3 also states that the baseline cycle counting results were projected to 60 years, and that the projected cycle counts were computed based on the actual accumulation history since the start of plant life. In addition, the cycle projections are based on a long term weighting (LTW) and short term weighting (STW) to obtain the most accurate projections of the future behavior of that event.

LRA Section 4.3.4 states that a method used to reduce the EAF CUF values includes using projected values of the accumulated number of transient events, which are provided in LRA Table 4.3-2, instead of using the 40-year number of events.

Issue:

It is not clear to the staff if, during the applicant's review of the transient event history, the applicant confirmed that the severity of the transients that occurred were bounded by the severity of the design transient.

In addition, since the applicant used the 60-year transient projections in its EAF fatigue analyses, additional information is needed about the LTW and STW used by the applicant in its projection methodology for the staff to determine if it was appropriate and conservative.

Request:

- During the applicant's review of the transient event history, confirm that the severity of all transients that have occurred is bounded by the design severity of the transient. If not, describe the actions taken when the severity of an actual transient exceeded the design severity of the transient. Describe how the Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the design severity of a transient is not exceeded.

- Describe the LTW and STW used for the 60-year projection methodology of design transients listed in LRA Table 4.3-2. In addition, justify that this 60-year projection methodology is conservative. Identify the transients in LRA Table 4.3-2 to which the LTW and STW are applicable and identify the LTW and STW values.

- If any design transient in LRA Table 4.3-2 used a different 60-year projection methodology, other than the one discussed above (long and short term weighting), describe and justify that this "alternative" 60-year projection methodology is conservative.

STPNOC Response:

- During the review of the transient event history performed for license renewal, STP did not confirm that the severity of all transients that have occurred is bounded by the design severity of the transient. The plant operating procedures and technical specifications are designed to ensure that the severity of plant events is bounded by those described in the design analyses. The current procedure requires the control room to complete one daily screening data sheet. If a transient has occurred, a subsequent transient specific datasheet is completed to record the plant's conditions during the event. This information is forwarded to system engineering for validation and review. For license renewal, the procedure will be enhanced to require the review to ensure the severity of an event does not exceed design severity of the transient that is used in the design fatigue analyses. If the severity is exceeded, the individual event will be reviewed to determine its overall impact, and, if appropriate, the fatigue analysis and design specification will be revised.

- The LTW and STW values used for each transient are estimated by taking into account the history of each transient, number of cycles, distribution, and qualities of the transient itself. In general, it was assumed that the short term history was three times more likely to predict future performance than the long term history (i.e., STW = 3, LTW = 1). Short-term is 10 years which is approximately a third of the plant operating period. The exceptions to these criteria are those transients with a low number of occurrences that occur randomly and those that only occurred during initial plant testing. The table below identifies the transients that did not use STW = 3, LTW = 1, and a 10 year short-term period.

Transient	***LTW***	***STW***	***Short Term Period***
Unit 1 *Feedwater Cycle at Hot Shutdown*	*1*	*3*	*5*
Unit 2 *Feedwater Cycle at Hot Shutdown*	*1*	*0*	*5*
Unit 1 *Primary Side Leak Test*	*0*	*1*	*5*
Units 1 & 2 *Turbine Roll Test*	*0*	*1*	*5*
Unit 1 *Charging Flow 50% Step Increase and Return*	*1*	*0*	*5*
Units 1 & 2 *Reactor Trip from Full Power, with Cooldown, with Safety Injection*	*1*	*0*	*10*
Unit 1 *Control Rod Drop*	*1*	*0*	*10*
Units 1 & 2 *Primary Side Hydrostatic Test*	*0*	*1*	*5*
Units 1 & 2 *Secondary Side Hydrostatic Test (each generator)*	*0*	*1*	*5*
Unit 1 *High Head Safety Injection*	*1*	*0*	*10*

- The only transient projections that differ from the methodology described above are those transients with no history. For those events with no accumulated cycles, at least one event was assumed for future operation

RAI 4.3-13

Background:

LRA Section 4.3.1.2 states that the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of the transients listed in LRA Table 4.3-2.

The following transients are listed in LRA Table 4.3-2:

- Transient 5, "Unit Loading at 5% of Full Power/min"
- Transient 6, "Unit Unloading at 5% of Full Power/min"
- Transient 10, "Steady State Fluctuations, Initial"
- Transient 11, "Steady State Fluctuations, Random"

- Transient 15, "Unit Loading Between 0-15% of Full Power"
- Transient 16, "Unit Unloading Between 0-15% of Full Power"
- Transient 17, "Boron Concentration Equalization"

LRA Table 4.3-2 also provides the following footnotes:

- Footnote 2 -Transients 10 and 11 "Steady State Fluctuations" are listed in UFSAR Table 3.9-8; however they are not projected and are marked as "NP." These transients do not have a significant effect on fatigue and are bounded by transients which are tracked.

- Footnote 5 -Transient 17 "Boron Concentration Equalization" is listed in UFSAR Table 3.9-8; however it is not projected and marked as "NP." This transient is bounded by load change transients which are tracked.

LRA Section 4.3.4 states that a method used to reduce the EAF CUF values included using projected values of the accumulated number of transient events, which are provided in LRA Table 4.3-2, instead of using the 40-year number of events.

Issue:

For all the transients listed above, LRA Table 4.3-2 does not provide a baseline number of cycles for Units 1 and 2; therefore it is not clear how the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of the transients.

For Transients 10 and 11, it is not clear how the applicant determined that these transients do not have a significant effect on fatigue. It is also not clear which transients are tracked by the applicant and how they bound Transients 10 and 11.

Based on footnote 5, it is not clear which load change transients that are tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program bound Transient 17.

Since 60-year projections were not provided for the transients listed above, it is not clear whether they were included into the applicant's EAF CUF calculations.

Request:

- Justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of the Transients 5, 6, 10, 11, 15, 16, and 17 without having a baseline number of cycles.

- Justify why Transients 10 and 11 do not have a significant effect on fatigue. Identify the tracked transients that bound Transients 10 and 11 and justify how these tracked transients bound Transients 10 and 11.

- Clarify the load change transients that are tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program that bound Transient 17. Describe and justify how these tracked load change transients bound Transient 17.

- Clarify whether Transients 5, 6, 10, 11, 15, 16, and 17 were included into the EAF CUF calculation. If they were included, provide the number of cycles that were used in these calculations. If not, justify why these transients can be excluded from the EAF CUF calculations.

STPNOC Response:

- Transients 5, 6, 10, 11, 15, 16 and 17 are not projected, as explained in the footnotes to Table 4.3-2. Therefore, these transients are not tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program, and a determination of the baseline number of cycles is not needed.

- Transients 10, "Steady State Fluctuations, Initial," and 11, "Steady State Fluctuations, Random," are both subcategories of steady state fluctuations. Transient 10 identifies fluctuations that are assumed to occur only during the first 20 full-power months of operation. Therefore, Transient 10 is not applicable for future operation. Transient 11 number of cycles is beyond the endurance limit of the ASME fatigue curves. Therefore, Transient 11 does not need to be managed for fatigue.

- Transient 17, "Boron Concentration Equalization," occurs following any large change in boron concentration in the reactor coolant system (RCS) by initiating spray in order to equalize boron concentration between the RCS loops and the pressurizer. For design purposes, it is assumed that this operation is performed after each load change in the load follow design cycle. With two load changes per day and a 90-percent plant availability factor over the 40-year design life, the total number of occurrences is 26,400 during the plant life. Transient 17 coincided with Transients 5 and 6. However, Transients 5 and 6 are not tracked. This number of events is consistent with load follow operation. The South Texas Project (STP) does not load follow and will not approach the limit. LRA Table 4.3-2, footnote 5 will be revised to note this is a load following transient.

- If a transient is not projected for the period of extended operation, then the design number of events is used in the EAF CUF calculations, if applicable. Transients 15 and 16 have negligible effect and were not included in the EAFCUF calculations. Transients 1 and 11 (Steady State Fluctuations), Transient 5 ("Unit Loading at 5% of Full Power/min," 13,200 cycles), Transient 6 ("Unit Unloading at 5% of Full Power/min," 13,200 cycles), and Transient 17 ("Boron Concentration Equalization," 26,400 cycles) are used in the hot leg surge nozzle EAF CUF calculation. Transients 5, 6, 10, 11, 15, 16 and 17 have negligible effect on EAF CUF calculations that use 60-year cycle projections for the charging nozzles and are not included in the calculations.

Enclosure 2 provides the line-in/line-out revision to footnote 5 of Table 4.3-2.

RAI 4.3-14

Background:

LRA Table 4.3-2 provides the following information for these selected transients:

Transient Description	Baseline Events up to Year end 2008		Projected events for 60-years	
	Unit 1	Unit 2	Unit 1	Unit 2
19 – Primary Side Leak Test	1	0	1	1
22 – Turbine Roll Test	9	5	9	5
43 – Primary Side Hydrostatic Test	1	1	1	1
44 – Secondary Side Hydrostatic Test (each generator)	1	1	1	1

LRA Section 4.3.4 states that a method used to reduce the EAF CUF values includes using projected values of the accumulated number of transient events, which are provided in LRA Table 4.3-2, instead of using the 40-year number of events.

Issue:

For the transients listed above, LRA Table 4.3-2 indicates that these transients are not expected to occur again through 60 years of operation, except Transient 19 for Unit 2. Since these projections may have been used in reducing the EAF CUF, it is not clear why these transients are not expected to occur again and whether this is conservative.

Request:

- Justify why Transients 19 (except for Unit 2), 22, 43, and 44 are not expected to occur again through 60 years of operation. In addition, explain why one cycle of Transient 19 for Unit 2 is expected to occur when no additional cycles of this transient are expected for Unit 1.

- Justify that the use of these projections are conservative for the EAF CUF calculations. If these projections were not used, clarify the number of cycles used for Transients 19, 22, 43, and 44 in the EAF CUF calculations.

STPNOC Response:

- Transients 19, 22, 43 and 44 are tests performed during initial startup and no more tests are expected. For Unit 2 Transient 19, since no cycles have accumulated to date, STP chose to project one assumed event.

- These projections were used in the EAF CUF calculations. These transients are tests performed during initial startup and are not expected to be performed again. The applicable locations (i.e., hot leg surge nozzle and charging nozzles) are monitored by

CBF. If these transients were to occur again, they would be tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program and incorporated in CBF generated EAF CUFs.

RAI 4.3-15

Background:

LRA Section 4.3.2.3 states that the reactor coolant pumps (RCP) for both units were designed to the Class 1 requirements of ASME Code Section III, 1971, with addenda through the summer 1973. Furthermore, the fatigue analyses for the RCPs were performed with transients provided in UFSAR Table 3.9-8, with additional cooling water and seal injection transients. The LRA also states that these analyses demonstrated code compliance for most reactor coolant pump components by satisfying the six criteria for a fatigue waiver per NB-3222.4(d).

LRA Section 4.3.2.3 also states that the TLAAs for the RCP pressure-retaining components are dispositioned in accordance with 10 CFR 45.21(c)(1)(iii), and that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage effects of fatigue for the period of extended operation.

Issue:

It is not clear from the information provided in LRA Sections 4.3.2.3 and B3.1, how the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will ensure that the fatigue waiver for RCP pressure-retaining components will remain valid during the period of extended operation. It is also not clear to the staff if the number of design cycles provided in UFSAR Table 3.9-8 were used in the applicant's analyses to demonstrate that the criteria for a fatigue waiver per NB-3222.4(d) were satisfied.

Request:

Specific to those RCP components and associated TLAAs that satisfied the six criteria for a fatigue waiver per NB-3222.4(d), describe how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage the effects of cumulative fatigue damage through the period of extended operation.

STPNOC Response:

A detailed fatigue evaluation is not required if a component conforms to the waiver of fatigue requirements of ASME Code paragraph NB 3222.4(d). These fatigue waiver requirements depend on the numbers of anticipated transients over the life of the plant. The fatigue waiver for the RCPs was performed with transients consistent with those in UFSAR Table 3.9-8 and verified to be equal to or less than the program limit value in LRA Table 4.3-2. The Metal Fatigue of Reactor Coolant Pressure Boundary program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number. Therefore the fatigue waivers will be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 4.3-16

Background:

LRA Section 4.3.2.5 states that the analyses of the replacement steam generators (RSG) show that the usage factors of the steam generator components are less than the allowable 1.0, as shown in LRA Table 4.3-5, except for the manway studs, which were qualified by fatigue tests. LRA Table 4.3-5 states that the cumulative usage factor for the primary manway studs for Unit 1 and 2 is 7.13 and is denoted with footnote 1, which states that fatigue usage exceeds the allowable of 1.0 and is qualified for 40 years by fatigue testing.

This LRA section also states that the fatigue usage factors in the replacement steam generator components do not depend on effects that are time dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The applicant dispositioned the TLAAs for the RSGs in accordance with 10 CFR 54.21(c)(1)(iii), such that effects of fatigue for the replacement steam generator components will be managed for the period of extended operation with the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Issue:

LRA Section 4.3.2.5 did not describe the details of the fatigue testing that was performed to qualify the primary manway studs for the Unit 1 and 2 RSGs. Therefore, it is not clear to the staff how the applicant will use its Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage cumulative fatigue damage of the primary manway studs, since they were described as qualified by fatigue testing.

Request:

- Describe how the primary manway studs for the Unit 1 and 2 RSGs were qualified for 40-years by fatigue testing. Identify sections of the applicable design codes that were used for the fatigue testing.

- Describe and justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage cumulative fatigue damage of the primary manway studs for the Unit 1 and 2 RSGs.

STPNOC Response:

- The bolt fatigue test was performed on bolts that represent the same thread size and material as the studs used in the primary manway studs. The number of fatigue test cycles was calculated to envelop, based on a 40 year life, the steam generator design transients. The fatigue test alternating stress amplitudes were based on a bolt fatigue analysis. The worst case alternating stress ranges of the stress intensity histogram was used to formulate the test stress intensity range for the bolt fatigue test. The fatigue test cycles and stress intensities envelop the primary manway stud cycles and stress intensity. Fatigue tests were performed in accordance with ASME Section III, Division 1, Appendix II-1500 as allowed per NB-3222.4(a). Therefore, the STP primary manway studs are qualified for fatigue by testing.

- The fatigue test data envelops the number of cycles and the severity of the transients required by the design specification. The Metal Fatigue of Reactor Coolant Pressure Boundary program ensures that the numbers and severity of transients actually experienced during the period of extended operation remain below that assumed. Therefore the ASME Code waiver of fatigue analysis by testing will be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 4.3-17

Background:

LRA Section 4.3.3 discusses the applicant's ASME Code Section III, Subsection NG, fatigue analysis of reactor pressure vessel internals. The applicant stated that Westinghouse evaluated the Unit 1 and 2 reactor vessel internals for the effects of the 1.4% uprating and that the assessment of core support structures' limiting margins of safety and fatigue usage factors resulted in meeting ASME Code allowable values as shown in LRA Table 4.3-7.

LRA Table 4.3-7 provides the limiting 40-Year CUF for Unit 1 and 2 of the "baffle, former assembly," which is <1 (test).

The applicant dispositioned the TLAAs in accordance with 10 CFR 54.21(c)(1)(iii), such that effects of fatigue for the reactor vessel internals will be managed for the period of extended operation with the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Issue:

LRA Section 4.3.3 did not describe the details of the test that was performed to determine that the CUF for the "baffle, former assembly" to be less than one. In addition, it is not clear to the staff how the applicant will use its Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage cumulative fatigue damage of the "baffle, former assembly," since the CUF is shown to be less than 1 by testing.

Request:

- Describe how the CUF for the "baffle, former assembly" for Unit 1 and 2 were shown to be less than 1 by testing. Identify sections of the applicable design codes that were used for the fatigue testing.

- Describe and justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage cumulative fatigue damage of the "baffle, former assembly" for Unit 1 and 2, since the CUF was shown to be less than 1 by testing.

STPNOC Response:

- A test was conducted in accordance with ASME Code Section III Subsection NG, Article II-1221 in an arrangement that models the baffle-former-barrel assembly of the top two formers for a width of three baffle-former bolts. The test was conducted by cyclically displacing the baffle relative to the barrel to the thermal displacement values. Following the test, an inspection was done to determine the baffle-former and barrel-former gaps. All bolts were deemed acceptable and survived cyclical deflection without exhibiting a significant loss of preload or any other characteristic of fatigue failure. The fatigue test data envelop the number of cycles and the severity of the transients required by the design specification.

- The baffle, former, and barrel assemblies were qualified by fatigue tests in accordance with ASME Section III for the number of cycles required by the design specification. The fatigue tests were used in lieu of a fatigue analysis; therefore, no CUF exists for these components. Maintaining those components within specified numbers of transients will ensure the tests remain valid. The Metal Fatigue of Reactor Coolant Pressure Boundary program ensures that the numbers and severity of transients actually experienced during the period of extended operation remain below those assumed. The fatigue waivers will therefore be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 4.3-18

Background:

LRA Section 4.3.5 discusses the TLAAs associated with assumed thermal cycle count for allowable secondary stress range reduction factor in ANSI B31.1 and ASME Code Section III, Class 2 and 3 piping. The LRA states that these are dispositioned in accordance with 10 CFR 54.21(c)(1)(i), and that the existing analyses of piping for which the allowable range of secondary stresses depends on the number of assumed thermal cycles and that are within the scope of license renewal are valid for the period of extended operation.

LRA Section 4.3.5 also states that temperature screening criteria (less than 220°F in carbon steel components and less than 270°F in stainless steel components) were used to identify components that might be subject to significant thermal fatigue effects.

The applicant stated:

> [A] systematic survey of all plant piping systems found that the piping and components in the scope of license renewal:
>
> - Do not meet the operating temperature screening criteria, and therefore do not experience significant thermal cycle stresses; or
> - Clearly do not operate in a cycling mode that would expose the piping to more than three thermal cycles per week, i.e. to more than 7,000 cycles in 60 years; or
> - The assumed thermal cycle count for the analyses depends closely on reactor operating cycles, and can therefore conservatively be approximated by the thermal cycles used in the ASME Section III Class 1 vessel and piping fatigue analyses.

10 CFR 54.21(a)(1) states that, for those systems, structures, and components within the scope of 10 CFR 54.4, structures and components subject to an aging management review are to be identified and listed. Additional requirements for those structures and components that are subject to an aging management review are described in 10 CFR 54.21(a)(1)(i) and 10 CFR 54.21(a)(1)(ii).

Issue:

The staff reviewed the applicant's AMR results in the associated LRA Tables (3.x.2-y) in LRA Sections 3.2, 3.3 and 3.4, and noted that they did not include the applicable AMR line items for the TLAAs associated with fatigue of non-Class 1 piping. It is not clear to the staff why the components analyzed for cumulative fatigue damage by the TLAAs discussed in LRA Section 4.3.5 are not included as AMR line items in LRA Sections 3.2, 3.3 and 3.4.

The staff noted that the applicant's results from its "systematic survey of all plant piping systems" do not permit the exclusion of structures and components from an aging management review and that the structures and components must still be listed and identified for aging management review in accordance with 10 CFR 54.21(a)(1).

Request:

- Clarify whether the techniques from the "systematic survey of all plant piping systems" were used to exclude AMR line items from LRA Tables (3.x.2-y) in LRA Sections 3.2, 3.3, and 3.4.

- If yes, justify how the use of this systematic survey satisfies 10 CFR 54.21(a)(1) or revise the applicable LRA Tables (3.x.2-y) in LRA Sections 3.2, 3.3, and 3.4 to include the AMR line items that address cumulative fatigue damage for non-Class 1 piping.

- If no, explain why there are no AMR line items in LRA Sections 3.2, 3.3, and 3.4 that are associated with the TLAA for ANSI B31.1 and ASME Code Section III, Class 2 and 3 piping discussed in LRA Section 4.3.5.

STPNOC Response:

The temperatures of in-scope piping systems were reviewed to determine if they exceeded the temperature screening criteria of 220°F in carbon steel components, or 270°F in stainless steel components. If the temperature was exceeded, the piping system was determined to be subject to thermal fatigue. The following systems were determined to include system components for which the temperature criteria were exceeded. The aging management review line items were inadvertently omitted from the LRA. The listed LRA tables will be revised to include these AMR line items.

Auxiliary Feedwater System	LRA Table 3.4.2-6
Auxiliary Steam System and Boilers	LRA Table 3.4.2-2
Chemical & Volume Control	LRA Table 3.3.2-19
Nonsafety-related Diesel Generator	LRA Table 3.3.2-21
Standby Diesel Generator	LRA Table 3.3.2-20
Main Steam	LRA Table 3.4.2-1

Primary Process Sampling	LRA Table 3.3.2-8
Steam Generator Blowdown	LRA Table 3.4.2-5
Liquid Waste Processing	LRA Table 3.3.2-22

Enclosure 2 provides the line-in/line-out revisions to the above LRA Tables.

RAI 4.3-19

Background:

LRA Section 4.3.4 states that the RPV Wall Transition, RPV Inlet Nozzle, and RPV Outlet Nozzle have a 60-year EAF CUF less than 1.0 when multiplied by the maximum applicable F_{en} value for low-alloy steels. The F_{en} value for the material was determined based on NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels." LRA Table 4.3-8 provides a F_{en} value of 2.455 for these low-alloy steel components.

Issue:

The staff noted that based on the guidance in NUREG/CR-6583 the F_{en} value is dependent on sulfur content, temperature, dissolved oxygen, and strain rate. In addition, the F_{en} value can vary significantly depending on dissolved oxygen content at the applicant's site. It is not clear to the staff what assumptions were used by the applicant in determining the F_{en} values for the low-alloy steel components.

Request:

- Clarify how the F_{en} values for the low-alloy steel components were determined and justify any assumptions on the parameters, such as sulfur content, temperature, dissolved oxygen, and strain rate, which were used. As part of the justification, confirm that the dissolved oxygen remained less than 0.05 ppm since initial plant operation. If it has not, justify that the F_{en} value of 2.455 is conservative and appropriate for the conditions at the plant.

- Justify that the dissolved oxygen content will remain less than 0.05 ppm during the period of extended operation, such that the F_{en} values are bounding for the conditions at the plant for the low-alloy steel components.

STPNOC Response:

- Strain rate and sulphur content were assumed to be worst case for the F_{en} value for low-alloy steel components. The dissolved oxygen level was assumed to be less than 0.05 ppm, which corresponds to a low oxygen environment. The dissolved oxygen level only affects the F_{en} calculation when the reactor coolant system (RCS) temperature is greater than 150°C (302°F). The assumption is consistent with the STP primary chemistry program which maintains the dissolved oxygen at less than 0.005 ppm when the temperature is greater than 250°F. Typically during steady state operation, the RCS dissolved oxygen is at levels close to or below detection limit of 0.001 ppm. A review of

STP primary water chemistry history identified only one occurrence of short duration (approximately 2 hours) where the RCS dissolved oxygen exceeded 0.05 ppm while RCS temperature was greater than 250°F.

- The STP primary chemistry program maintains the dissolved oxygen at less than 0.005 ppm when the RCS temperature is greater than 250°F. Review of the water chemistry history confirms the effectiveness of the chemistry program. This program will be continued through the extended period of operation.

RAI 4.3-20

Background:

LRA Section 4.3.2.10 states that the fatigue crack growth analyses for the pressurizer surge line and accumulator safety injection lines established that flaws would not reach the flaw depths allowed in paragraph IWB-3640 of the ASME Code during the plant life. The applicant also stated that the analyses that evaluated fatigue crack growth and cumulative usage factor in the pressurizer surge line and the accumulator safety injection line depend on the standard number of cycles for a 40-year reactor lifetime. Therefore these analyses are TLAAs.

Issue:

The staff noted that LRA Section 4.3.2.10 provides two TLAA dispositions: "Projection, 10 CFR 54.21(c)(1)(ii); and Aging Management, 10 CFR 54.21(c)(1)(iii)." However, it is not clear to the staff how the analyses that evaluated fatigue crack growth for the pressurizer surge line and accumulator safety injection lines were dispositioned.

Specifically, for the disposition in accordance with 10 CFR 54.21(c)(1)(ii), the applicant did not provide any information to justify that these analyses have been projected to the end of the period of extended operation.

In addition, for the disposition 10 CFR 54.21(c)(1)(iii), the staff noted that the applicant's Fatigue Monitoring Program is based on GALL AMP X.M1, which is limited to the use of cycle counting for CUF analyses (e.g. ASME Code Section III, CUF analyses and environmentally-assisted CUF analyses); therefore, the use of cycle counting to manage crack growth is not covered by GALL AMP X.M1. The staff also noted that enhancements to the applicable program elements (e.g. "scope of program," "parameters monitored or inspected," "monitoring and trending," "acceptance criteria," or "corrective action") are needed to provide justification for all cycle counting design transients that were assumed in the fatigue crack growth analysis.

Request:

Provide the TLAA disposition for the analyses that evaluated fatigue crack growth of the pressurizer surge line and the accumulator safety injection lines.

- If the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii), provide sufficient information related to the fatigue crack growth analyses to justify the selected disposition.

- If the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) and the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be used, justify the use of cycle counting for these fatigue crack growth analyses without an update to the cycle counting procedure and the inclusion of enhancements to the applicable program elements.

STPNOC Response:

The fatigue crack growth analyses for the pressurizer surge line and the accumulator safety injection lines are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). LRA Section 4.3.2.10 will be revised to read:

> *Aging Management of Class 1 Break Locations and Welded Attachments to Charging and Main Feedwater Lines*
>
> Break locations, which depend on usage factor, and the fatigue crack growth analyses, which support the increase in the CUF for break considerations in the pressurizer surge and accumulator lines, will remain valid as long as the numbers of cycles assumed by the analysis are not exceeded. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 4.3.1 and Section B3.1 ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number, or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The program also ensures that the charging line weld attachments CUF will be below the Code allowable. The effects of fatigue will therefore be managed for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Appendix A3.2.1.10 fifth paragraph will be revised to read:

> The Class 1 break locations, the fatigue crack growth analyses, which support the increase in the CUF for break considerations in the pressurizer surge and accumulator lines, and welded attachments to charging and the main feedwater systems which depend on usage factor will remain valid as long as the numbers of cycles assumed by the analysis are not exceeded.....

In response to RAIs 4.3.2.11-1 and B3.1-3, LRA Appendix B3.1 was revised to include the following enhancements:

> Element 1: the scope of the program will include monitoring fatigue crack growth analyses to ensure that they remain valid by counting the transients used in the analyses.
>
> Element 7: corrective actions include a review the fatigue crack growth analyses which support the leak before break exemptions to ensure that the analytical bases remain valid. Re-analysis of a fatigue crack growth analysis must be consistent with, or reconciled to, the originally submitted analysis and receive the same level of regulatory review as the original analysis.

The response to B3.1-3 also identifies the applicable transients for these analyses.

Enclosure 2 provides the line-in/line-out revisions to LRA Section 4.3.2.10 and LRA Appendix A3.2.1.10.

RAI 4.3-21

Background:

LRA Section 4.3.2.8 states that any supporting fatigue analyses related to thermal cycling for normal charging, alternate charging, and the auxiliary spray lines are not TLAAs in accordance with 10 CFR 54.3(a), Criterion 3, in that the fatigue analyses did not involve a time-limited assumption.

Issue:

In the staff's safety evaluation (SE) related to the resolution of Bulletin 88-08, dated May 6, 1998 (ADAMS Legacy Accession Number 9805110004), the applicant estimated that the ASME CUF limit of 1.0, when considering design transients and inadvertent thermal stratification cycling, would be achieved in a time span of 11.4 years based on a fatigue evaluation, performed by Westinghouse, of the weld between the check valve and the unisolable piping. In this SE, the staff noted that the time span was calculated using the assumption that thermal cycling occurred at the check valve weld and that the ASME CUF limit would not be achieved at the weld during the life of the plant (40 years) without the assumption of thermal cycling. It is not clear to the staff why the fatigue analyses performed by the applicant, which included time-limited assumptions, would not be defined as a TLAA, in accordance with 10 CFR 54.3(a).

Request:

Based on the staff's SE dated May 6, 1998, justify why the fatigue analyses related to thermal cycling were not identified as TLAAs, as defined in 10 CFR 54.3(a). Or provide and justify the TLAA disposition for the fatigue analyses of the weld between the check valve and the unisolable piping related to thermal cycling for the normal charging, alternate charging, and the auxiliary spray lines.

STPNOC Response:

The analysis noted in the staff safety evaluation (SE) related to the resolution of Bulletin 88-08, dated May 6, 1998 (ADAMS Legacy Accession Number 9805110004) was generated to form the interim basis for continuing normal operation at STP assuming thermal cycling at the check valve weld was occurring. In the SE, the Staff concluded that the normal charging, alternate charging, and the auxiliary spray lines at STP are not susceptible to the thermal cycling. Therefore, the fatigue analysis is no longer part of the CLB, and the analysis is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 6.

RAI 4.3-22

Background:

LRA Section 4.3.2.6 provides the TLAA for ASME Code Section III, Class 1 valves and LRA Table 4.3-6 provides a summary of the applicant's Class 1 valve fatigue analyses. The applicant dispositioned the following Class 1 valves in accordance with 10 CFR 54.21(c)(1)(ii), that the design of these valves for fatigue is valid for the period of extended operation:

- 6 inch pressurizer safety relief valves
- 6 inch hi-head safety injection pump discharge check valves
- 8 inch hi-head safety injection pump discharge check valves
- 8 inch lo-head safety injection to hot leg check valves
- 12 inch safety injection to cold leg injection check valves
- 12 inch safety injection accumulator outlet valves
- 2 inch CVCS auxiliary spray check valves
- 2 inch RCP seal injection first check valves
- 2 inch RCP seal injection second check valves

The applicant dispositioned the 12 inch RHR pump suction isolation valves in accordance with 10 CFR 54.21(c)(1)(iii), that the aging effects of the Class 1 valve pressure boundaries will be managed for the period of extended operation by the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Issue:

The staff noted that LRA Table 4.3-6 provides the fatigue results for the "8 inch Lo Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" and the "3 inch X 6 inch Pressurizer Power Operated Relief Valve," but does not provide a disposition for these valves. Therefore, it is not clear how the applicant has dispositioned the TLAAs for these valves in accordance with 10 CFR 54.21(c)(1).

Request:

Provide and justify the dispositions for the fatigue TLAA of the "8 inch Lo Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" and the "3 inch X 6 inch Pressurizer Power Operated Relief Valve," in accordance with 10 CFR 54.21(c)(1). Provide the appropriate revisions to LRA Section 4 and Appendix A.

STPNOC Response:

The calculated worst-case usage factors for the "8 inch Lo Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" (I_t, 40 = 0.14) and the "3 inch X 6 inch Pressurizer Power Operated Relief Valve," (I_t, 40 = 0.16) indicate that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design life (60 years / 40 years)). The design of these valves for fatigue effects is therefore valid for the period of extended operation, and these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

LRA Section 4.3.2.6 and Appendix A3.2.1.6 will be revised to note the Lo Head Safety Injection Cold Leg Check Valve and PORV valves are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

Enclosure 2 provides the line-in/line-out revision to LRA Section 4.3.2.6 and LRA Appendix A3.2.1.6.

Aluminum (070)

RAI 3.2.1.50-1

Background:

LRA Table 3.3.2-17, page 3.3-181, includes an AMR item for a carbon steel valve exposed to fuel oil. The AMR item states that there is no aging effect requiring management and no AMP is proposed. The AMR item references LRA Table 3.2.1, item 3.2.1-50, and cites generic note A. However, item 3.2.1-50 is for aluminum components exposed to indoor uncontrolled air, not for carbon steel components exposed to fuel oil.

The GALL Report, Revision 2, items VII.H1.AP-105 and VII.H2.AP-105, state that carbon steel piping, piping components, piping elements, and tanks exposed to fuel oil are susceptible to loss of material and recommend GALL AMP XI.M30, "Fuel Oil Chemistry," and XI.M32, "One-time Inspection," to manage the aging effect.

Issue:

The references to LRA Table 3.2.1, item 3.2.1-50 and generic note A appear to be incorrect. It is unclear to the staff how this item is being appropriately managed for loss of material, as recommended by the GALL Report.

Request:

Revise the AMR item for the carbon steel valve exposed to fuel oil in LRA Table 3.3.2-17 to correct any errors in the line and to provide an appropriate AMP to manage loss of material; or explain why the valve is not susceptible to loss of material.

STPNOC Response:

The AMR line in LRA Table 3.3.2-17, page 3.3-181 for carbon steel valve exposed to fuel oil will be revised from GALL AMR Line V.F.2 to specify GALL AMR line VII.H2-24 and aging management program B2.1.14, Fuel Oil Chemistry and B2.1.16, One-Time Inspection for aging management of carbon steel valves exposed to fuel oil (internal).

Enclosure 2 provides the line-in/line-out revision to Table 3.3.2-17.

Cast Austenitic Stainless Steel (073)

RAI 3.1.1.80-1

Background:

The GALL Report, Revision 2, item IV.B2.RP-382, recommends that cracking or loss of material of the RVI core support structure, made of stainless steel, nickel alloy, and CASS, should be managed by GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." Examination Category B-N-3 in Table IWB-2500-1 of the 2004 edition of the ASME Code Section XI specifies visual VT-3 examination of the removable core support structures. The staff noted that the inspections in accordance with Examination Category B-N-3 of the ASME Code Section XI can also provide indirect evidence of loss of fracture toughness.

LRA Table 3.1.1, item 3.1.1-80 addresses CASS reactor vessel internals (RVIs), which are exposed to the reactor coolant and subject to loss of fracture toughness due to thermal aging and neutron irradiation embrittlement. LRA item 3.1.1-80 also indicates that the aging effect is not applicable based on EPRI 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227)," Revision 0, issued in December, 2008. Specifically, LRA Table 3.1.2-1 states that, consistent with EPRI 1016596 (MRP-227), loss of fracture toughness is not an applicable aging effect requiring management for the RVI CASS upper core support -upper support column base.

In addition, LRA Table 3.1.2-1 addresses an AMR item to manage loss of material of the CASS upper core support - upper support column base using the Water Chemistry Program. However, in comparison with the GALL Report, Revision 2, item IV.B2.RP-382, LRA Table 3.1.2-1 does not address an AMR item that uses the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material of the upper support column base and the other core support structure components.

Issue:

LRA Table 3.1.2-1 does not address an AMR item that uses the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material of the CASS upper support column base and the other core support structure components, even though the core support structure components made of stainless steel, nickel alloy, and CASS materials are susceptible to cracking and loss of material in the reactor coolant environment. The GALL Report, Revision 2, item IV.B2.RP-382, recommends the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage these aging effects.

Request:

Since the core support structures made of stainless steel, nickel alloy, and CASS materials are susceptible to cracking and loss of material in the reactor coolant environment, provide justification as to why LRA Table 3.1.2-1 does not identify an AMR item that uses the GALL Report recommendation of ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material of the core support structures.

STPNOC Response:

GALL Report Rev 2 contains a new item, IV.B2.RP-382, that requires management of cracking or loss of material due to wear of stainless steel, cast austenitic stainless steel, and nickel alloy reactor vessel internal (RVI) core support structures with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1). LRA Table 3.1.2-1 does not include AMR lines for ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material of the CASS upper support column base and the other core support structure components made of stainless steel, nickel alloy, and CASS materials that are susceptible to cracking and loss of material in the reactor coolant environment.

LRA Table 3.1.2-1 will be revised to add AMR lines that manage cracking and loss of material due to wear with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program for RVI core support structures that are fabricated from stainless steel, cast austenitic stainless steel, and nickel alloy. The Table 3.1.2-1 revision will also include changes to bring management of aging effects into alignment with EPRI-1016596 (MRP-227).

LRA Table 3.1.1 lines 3.1.1.30 and 3.1.1.37 will be revised to be consistent with NUREG 1801.

LRA Sections 3.1.2.2.12 and 3.1.2.2.17 will be revised to state that cracking is managed by ASME Section XI Inservice Inspection (B2.1.1) and add the additional components added to LRA Table 3.1.2-1.

Enclosure 2 provides the line-in/line-out revision to LRA Sections 3.1.2.2.12 and 3.1.2.2.17, and LRA Tables 3.1.1 and 3.1.2-1.

RAI 3.1.1.80-2

Background:

LRA Table 3.1.1, item 3.1.1-80, addresses loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals exposed to reactor coolant. It also states that this aging effect is not applicable based on MRP-227. LRA Section B2.1.35 states that the PWR Reactor Internals Program implements the guidance of EPRI 1016596 (MRP-227) and EPRI 1016609, "Inspection Standard for PWR Internals (MRP-228)," Revision 0. LRA Section B2.1.35 also states that the program manages aging consistent with the inspection guidance for Westinghouse designated primary components in Table 4-3 of MRP-227 and Westinghouse designated expansion components in Table 4-6 of MRP-227.

MRP-227, which is referenced in the GALL Report, Revision 2, categorizes the reactor vessel internal components to the following functional groups: primary, expansion, existing programs, and no additional measures. It also specifies relevant examination methods and coverage for the expansion group components based on the examination findings of the primary group components.

The GALL Report, Revision 2, items IV.B2.RP-297, IV.B2.RP-290, and IV.B2.RP-292, and

MRP-227 Tables 3-3, 4-3, 4-6, and 5-3 indicate that in Westinghouse plants, the control rod guide tube (CRGT) assembly lower flanges made of CASS are subject to loss of fracture toughness and are the primary components that are linked to the following expansion components: (1) lower support assembly lower support column bodies made of CASS; and (2) bottom-mounted instrumentation (BMI) system BMI column bodies made of stainless steel.

Issue:

In contrast with the GALL Report, Revision 2 and MRP-227, LRA Table 3.1.2-1 does not identify the functional groups and link relationships (for example, primary/expansion relationship) for the following components: (1) CRGT assembly lower flanges; (2) lower support assembly lower support column bodies; and (3) BMI column bodies. The staff needs this information regarding the functional groups and link relationships in order to evaluate the adequacy of the applicant's aging management methods, because the examination methods and coverage for the expansion group components are based on the examination findings of the primary group components.

Request:

1. Describe the functional groups for the following components: (1) CRGT assembly lower flanges made of CASS; (2) lower support assembly lower support column bodies made of CASS; and (3) BMI column bodies made of stainless steel. In addition, describe the link relationships for these components (such as primary/expansion link).

   If the assigned functional groups or links are not consistent with MRP-227 and the applicant's evaluation of its operating experience, justify why the inconsistency is acceptable to manage loss of fracture toughness of these components.

2. Revise LRA Table 3.1.2-1 and other related information in the LRA consistent with the applicant's response.

STPNOC Response:

1. In MRP-227, the primary functional group is those PWR internals that are highly susceptible to the effects of at least one of the eight aging mechanisms components were screened against during the creation of the MRP. The expansion functional group is composed of those PWR internals that were determined during the MRP-227 creation process to be highly or moderately susceptible to the effects of one of the eight aging mechanisms, but for which a functionality assessment has shown a degree of tolerance to those effects. Primary components are linked to expansion components that may experience the same aging effect, so that if aging is detected during examination of the primary component, then examination of the expansion component will be required. All components in the primary functional group must be examined, while components in the expansion functional group only need inspection when indications are found in the primary component to which they are linked.

   In MRP-227, the (1) Control Rod Guide Tube Assembly Lower Flange Welds are in the primary functional group with a link to the expansion group components of (2) Lower Support

Assembly - Lower Support Column Bodies (CASS), and (3) Bottom Mounted Instrumentation System – Bottom-mounted Instrumentation (BMI) Column Bodies.

The MRP-227 primary component of Control Rod Guide Tube Assembly - Lower Flange Welds, is a sub-component of the RVI Control Rod Guide Tube (CRGT) Assembly listed in STP LRA Table 3.1.2-1. The CRGT lower flanges are fabricated of stainless steel. In LRA Table 3.1.2-1, cracking of the RVI CRGT Assembly is shown to be managed with the PWR Vessel Internals program (B2.1.35). Cracking is the only aging effect managed by MRP-227 for the CRGT lower flange welds. Management of aging of the STP CRGT assembly lower flanges with the PWR Vessel Internals Program (B2.1.35) is consistent with MRP-227.

MRP-227 lists an expansion group component for Lower Support Assembly - Lower Support Column Bodies (CASS). STP has an extended core that does not use Lower Support Columns. Therefore the MRP-227 component for Lower Support Column bodies is not applicable to STP.

The MRP-227 expansion group component Bottom Mounted Instrumentation System – Bottom-Mounted Instrumentation (BMI) Column Bodies is listed in LRA Table 3.1.2-1 as RVI ICI Support Structures-Instrument (BMI) column. LRA Table 3.1.2-1 shows that cracking of these components is managed using the PWR Vessel Internals program (B2.1.35). Cracking is the only aging effect managed by MRP-227 for the BMI column bodies. Management of aging of the STP BMI column bodies with the PWR Vessel Internals Program (B2.1.35) is consistent with MRP-227.

The NRC requested additional information from EPRI during their review of MRP-227, as to how the program managed loss of fracture toughness when no inspections were defined to examine for loss of fracture toughness. EPRI responded that loss of fracture toughness is identified through implementation of MRP-227 by evaluation of cracking detected during examinations by using the evaluation acceptance criteria and methodologies developed by the PWROG Materials Subcommittee for identifying loss of fracture toughness. Upon detection of cracking in a component susceptible to loss of fracture toughness, the program defines an assessment of cracking with limit load and/or fracture mechanics evaluations.

2. Revision of LRA Table 3.1.2-1 is not necessary. Management of the (1) Control Rod Guide Tube Assembly Lower Flange Welds, and (3) BMI Column Bodies are already managed consistent with MRP-227. The (2) Lower Support Assembly - Lower Support Column Bodies are not used at STP due to the extended core design.

<u>RAI 3.4.2.6-2</u>

<u>Background:</u>

LRA Table 3.4.2-6 indicates that CASS valves exposed to atmosphere/weather have no aging effect requiring management; therefore, no aging management program is proposed for the components. LRA Table 3.0-1 indicates that the atmosphere/weather environment consists of moist, ambient temperatures, humidity, and exposure to weather, including precipitation and wind. It also indicates that the component is exposed to air and local weather conditions. Furthermore, it indicates that the atmosphere/weather environment corresponds to the

Air -Outdoor, Air-Outdoor (External) (includes salt-laden atmospheric air and salt water spray) and Air-Indoor and Outdoor environments described in the GALL Report.

SRP-LR, Revision 2, Sections 3.4.2.2.2 and 3.4.2.2.3, address cracking due to stress corrosion cracking (SCC) and loss of material due to pitting and crevice corrosion, respectively, of stainless steel components in the steam and power conversion system. SRP-LR, Revision 2, also states that applicable outdoor air environments (and associated indoor air environments) include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within 1/2 mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources.

The GALL Report, Revision 2, items VIII.D1.SP-118 and VIII.D1.SP-127, recommend AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to manage these aging effects. In addition, SRP-LR, Revision 2, states that the GALL Report recommends further evaluation to determine whether an adequate aging management program is used to manage this aging effect based on the environmental conditions applicable to the plant and ASME Code Section XI, requirements applicable to the components.

Issue:

In contrast with the guidance of SRP-LR, Revision 2, and the GALL Report, Revision 2, the LRA does not address the evaluation of environmental conditions in determining whether cracking due to SCC and loss of material due to pitting and crevice corrosion are applicable to the CASS valves. The staff needs the following information to determine the applicability of these aging effects to the CASS valves in the atmosphere/weather environment: (1) evaluation of the site environmental conditions in terms of its effect on occurrence of stress corrosion cracking and pitting and crevice corrosion of these components; and (2) relevant operating experience including the results of applicable ASME Code Section XI inservice inspections.

Request:

1. For each unit, provide detailed information regarding the system and location of the CASS valves exposed to the atmosphere/weather environment (for example, valves installed on the supply piping from the auxiliary feedwater storage tank).

2. Justify why the atmosphere/weather environment at the site is not conducive to stress corrosion cracking, pitting corrosion and crevice corrosion. In the justification, consider that the facility is close enough to a saltwater coastline so that sufficient halides can be deposited on the components, thereby facilitating stress corrosion cracking and pitting and crevice corrosion.

   As part of the response, if the components are covered or protected against direct wetting due to rain, snow and similar weather conditions (for example, by a roof, coating, or protection structure), describe how the components are covered or protected against these environmental conditions.

3. Describe applicant's operating experience related to these CASS valves exposed to the atmosphere/weather environment in terms of the occurrence of stress corrosion cracking, and pitting and crevice corrosion. As part of the response, discuss the results of applicable ASME Code Section XI, inservice inspections and system walk-downs.

4. If the applicant's evaluation of the environmental conditions or operating experience indicates potential for stress corrosion cracking, pitting corrosion or crevice corrosion, propose an aging management program to manage cracking and loss of material of these components.

STPNOC Response:

1. There are two cast austenitic stainless steel (CASS) valves exposed to an external environment of outdoor air. The valves are the non-safety related emergency fill valves located on top of the Unit 1 & 2 auxiliary feedwater storage tanks (AFWST). The valves are in-scope for structural integrity attached. The valves are not covered or protected from direct wetting from atmospheric conditions.

2. The prevailing outdoor air at South Texas Project (STP) is not an aggressive halide environment. The plant is not within five miles of a saltwater coastline, there are no roads treated with salt in the winter within 1/2 mile of the plant, the soil does not contain more than trace chlorides, there are no chlorine treated water sources nearby, and the outdoor environment is not subject to industry pollution. The closest industrial facility is 4.8 miles away. The land adjacent to the plant is open range for cattle and farming. There are no large concentrations of cattle within five miles of the plant that could generate excessive detrimental gases or concentrated solid waste.

3. There is no runoff from the adjacent land onto the plant site. Local rain tends to wash the outside surfaces of components rather than concentrate contaminates. There has been no plant-specific operating experience for these valves associated with aging effects of CASS exposed to the outdoor environment.

4. CASS valves exposed to an atmosphere/weather environment at STP have no aging effects requiring management.

RAI 3.1.2.2.7.2-1

Background:

LRA item 3.1.1-24 and LRA Section 3.1.2.2.7.2 state that, for managing cracking due to stress corrosion cracking of CASS piping components exposed to reactor coolant, the Water Chemistry Program is augmented by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to ensure that adequate inspection methods are used to detect cracks. LRA Table 3.1.2-2 indicates that these aging management review results by the applicant are consistent with the GALL Report, item IV.C2-3.

By comparison, the GALL Report, item IV.C2-3, recommends the Water Chemistry Program and a plant-specific program to manage cracking due to stress corrosion cracking of Class 1

CASS piping, piping components, and piping elements and that this plant-specific program should include adequate inspection methods to ensure detection of cracks.

Appendix VIII, Supplement 9 of the 2004 edition of the ASME Code Section XI, Division 1 indicates that the qualification requirements for ultrasonic examination of CASS piping welds are in the course of preparation. The "detection of aging effects" program element of the GALL Report, Revision 2, AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," addresses inspection methods for CASS components by stating that current ultrasonic testing (UT) methodology cannot detect and size cracks in CASS components; thus, enhanced visual examination (EVT-1) is used until qualified UT methodology for CASS can be established. AMP XI.M12 further states that a description of EVT-1 is found in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 (Revision 6) and Materials Reliability Program (MRP)-228 for PWRs.

Issue:

Even though LRA Section 3.1.2.2.7.2 states that the Water Chemistry Program is augmented by the ASME Section XI Inservice Inspection. Subsections IWB, IWC, and IWD Program to ensure adequate inspection methods for detection of cracks, the LRA does not provide the specific inspection methods to be used to ensure the detection of cracks in the CASS piping components.

Request:

Considering that currently there is no qualified UT methodology for the detection of cracks in CASS piping components, describe the inspection methods that will be used to detect cracking due to SCC in the CASS piping components, and justify why these inspection methods are adequate to detect and manage the aging effect.

STPNOC Response:

The CASS components represented in LRA Table 3.1.1, Item 3.1.1-24 are the Class 1 Reactor Coolant system pump casings, piping and fittings.

STP acknowledges that current ultrasonic examination methods are not adequate for reliable detection of cracks in CASS components. STP follows the industry initiatives focused on the development of an ultrasonic examination technique that can be demonstrated through a program consistent with the ASME Section XI, Appendix VIII.

During the period of extended operation, should the STP ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD program with NRC approved alternatives, require volumetric examinations be performed per ASME Section XI, Table IWB-2500-1, Examination Category B-J, on the Class 1 CASS pipe welds, then an ultrasonic examination method qualified under ASME Section XI, Appendix VIII will be utilized or an NRC approved alternative will be implemented.

STP currently uses an NRC approved alternative method of manual ultrasonic examination of centrifugally cast and static cast stainless steel piping welds. The alternative method, as demonstrated to the NRC during PSI, uses dual, focused, 0.5MHz transducers on wedges conforming to the curvature of the pipe. This alternative method will be implemented until an ASME Section XI, Appendix VIII ultrasonic examination method is qualified or an alternative is approved by the NRC.

RAI 3.1.2.1-1

Background:

LRA Table 3.1.2-1 for the reactor vessel, reactor vessel internals, and reactor coolant system does not address AMR items consistent with the GALL Report, Revision 2, items IV.B2.RP-265, IV.B2.RP-267, IV.B2.RP-268, and IV.B2.RP-269 for the components with no additional measures and the aging effects in inaccessible locations.

The GALL Report, Revision 2, item IV.B2.RP-267, addresses loss of fracture toughness due to neutron irradiation embrittlement, changes in dimension due to void swelling, loss of preload due to thermal and irradiation enhanced stress relaxation, and loss of material due to wear of the stainless steel and nickel alloy reactor vessel internal (RVI) components with no additional measures, which are managed by GALL AMP XI.M16A, "PWR Vessel Internals." Similarly, the GALL Report, Revision 2, item IV.B2.RP-265, addresses cracking due to SCC and irradiation-assisted stress corrosion cracking (IASCC) of the stainless steel and nickel alloy RVI components with no additional measures, which are managed by GALL AMPs XI.M2, "Water Chemistry," and XI.M16A, "PWR Vessel Internals".

In addition, the GALL Report, Revision 2, item IV.B2.RP-269, recommends GALL AMP XI.M16A, to manage loss of fracture toughness due to neutron irradiation embrittlement, changes in dimension due to void swelling, loss of preload due to thermal and irradiation enhanced stress relaxation, and loss of material due to wear in inaccessible locations of the stainless steel and nickel alloy RVI components. Similarly, the GALL Report, Revision 2, item IV.B2.RP-268, recommends GALL AMPs XI.M2 and XI.M16A, to manage cracking due to SCC and IASCC in accessible locations of stainless steel and nickel alloy RVI components. These two AMR items and SRP-LR, Revision 2, Sections 3.1.2.2.9 and 3.1.2.2.10 recommend that if an aging effect is identified in the accessible locations of the components, further evaluation should be performed on a plant-specific basis to ensure that the aging effect is adequately managed in the inaccessible locations.

Issue:

The GALL Report, Revision 2, addresses items IV.B2.RP-267 and IV.B2.RP-265 for the components with no additional measures. MRP-227 addresses the "No Additional Measures" functional group and indicates that the components in this functional group do not require additional measures for aging management as screened in MRP-227, even though these components are included in the scope of the applicant's aging management. In addition, the GALL Report, Revision 2, addresses items IV.B2.RP-269 and IV.B2.RP-268 to ensure adequate aging management for the inaccessible locations of the RVI components in consideration of aging effects identified in the accessible locations. By contrast, LRA Table 3.1.2-1 for the reactor vessel, reactor vessel internals, and reactor coolant system does not address AMR items consistent with the GALL Report, Revision 2, items IV.B2.RP-265, IV.B2.RP-267, IV.B2.RP-268, and IV.B2.RP-269 for the components with no additional measures and aging effects in inaccessible locations.

Request:

Provide justification as to why LRA 3.1.2-1 does not address AMR items consistent with the GALL Report, Revision 2, items IV.B2.RP-265, IV.B2.RP-267, IV.B2.RP-268, and IV.B2.RP-269 for the components with no additional measures and aging effects in inaccessible locations. If it cannot be justified, revise the LRA consistent with these AMR items in the GALL Report, Revision 2. In addition, if an aging effect has been identified in accessible locations of the reactor vessel internal components, provide further evaluation to ensure that the aging effect is adequately managed for the inaccessible locations as recommended in the GALL Report, Revision 2, and SRP-LR, Revision 2.

STPNOC Response:

NUREG-1801 Rev 2 items IV.B2.RP-265 and IV.B2.RP-267 apply to the reactor vessel internal components with no additional aging measures as defined in Section 3.3.1 of EPRI MRP-227. MRP-227 states that No Additional Measures Components are those PWR internals for which the aging effects of all eight aging mechanisms are below the screening criteria. Components that were screened out as a result of the failure modes, effects, and criticality analyses (FMECA) and functionality assessments were added to the No Additional Measures group. Because MRP-227 indicates that aging effects for these components are below the screening criteria, and does not identify aging management for these components, the components are considered equivalent to an aging evaluation item with no aging effects and no aging management program. Cracking of components in the MRP-227 No Additional Measures group is managed by the Water Chemistry program, and in some cases the ASME Section XI Inservice Inspection Program category B-N-3 inspections.

NUREG-1801 Rev 2 items IV.B2.RP-268 and IV.B2.RP-269 provide aging management to reactor vessel internal components in inaccessible locations. However the final NRC Safety Evaluation of MRP-227, dated June 22, 2011 was released after GALL Rev 2 was issued, and contains a different strategy for managing inaccessible components. The Safety Evaluation defines minimum examination coverage criteria for stainless steel and nickel alloy reactor vessel internal primary and expansion inspection category components that are subject to cracking, loss of fracture toughness, changes in dimension, loss of preload, or loss of material. One hundred percent of the volume/area of each accessible component must be examined. The minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total (accessible plus inaccessible) inspection area/volume be examined or, when addressing a set of like components (e.g. bolting), the inspection must examine a minimum sample size of 75 percent of the total population of like components. A technical justification will be required of any minimum coverage requirements below 75 percent of components total inspection area/volume or sample size. The PWR Reactor Internals program (B2.1.35) is consistent with these conditions from Section 3.3.1 of the MRP-227 Safety Evaluation.

Copper Alloy (075)

RAI 3.3.2.3.10-1

Background:

LRA Tables 3.3.2-10 and 3.3.2-20 include AMR items for copper alloy tubing exposed to ventilation atmosphere (internal) and for copper alloy valves exposed to plant indoor air (internal), respectively. For each of these items, the LRA states that there is no aging effect and no aging management program is recommended. The AMR items cite generic note G, indicating that environment is not in the GALL Report for the component and material combination.

LRA Table 3.0-1, Mechanical Environments, states that "ventilation atmosphere (internal)" encompasses the GALL Report environments of "air indoor - uncontrolled" and "condensation (internal.)" LRA Table 3.0-1 also states that "plant indoor air (when used as internal)" encompasses the GALL Report environments of "condensation (internal)," "air," and "moist air and condensation."

The GALL Report, item VII.G-9, AP-78, states that copper alloy piping, piping components, and piping elements exposed to condensation (internal) may experience loss of material due to pitting and crevice corrosion and recommends that a plant-specific aging management program be evaluated to manage the aging effect. However, the GALL Report, items VII.J-3, AP-8, and VIII.J-2, SP-6, also state that copper alloy piping, piping components, and piping elements exposed to dry air or uncontrolled indoor air have no aging effects requiring management and that no AMP is recommended.

Issue:

The LRA does not provide sufficient information for the staff to determine whether the copper alloy tubing and valves are exposed to moist or dry air environments; and, therefore, the staff cannot determine whether the applicant has appropriately evaluated all of the credible aging effects for these components.

Request:

State the normal environment for the copper alloy tubing exposed to ventilation atmosphere (internal) in LRA Table 3.3.2-10 and for the copper alloy valves exposed to plant indoor air (internal) in LRA Table 3.3.2-20, and provide the basis for the determination that these components have no aging effects requiring management during the period of extended operation.

STPNOC Response:

The normal environment for the copper tubing exposed to ventilation atmosphere (internal) in LRA Table 3.3.2-10 and for the copper alloy valves exposed to plant indoor air (internal) in LRA Table 3.3.2-20 is considered to be condensation (internal).

LRA Table 3.3.2-10 for the copper tubing exposed to ventilation atmosphere (internal) and LRA Table 3.3.2-20 for the copper alloy valves exposed to plant indoor air (internal) will be revised to specify GALL Line VII.G-9 for loss of material/pitting and crevice corrosion. Aging management program B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components will be used for aging management.

Enclosure 2 provides the line-in/line-out revision to LRA Tables 3.3.2-10 and 3.3.2-20.

Elastomers (079)

RAI 3.3.2.3.18-1

Background:

In LRA Table 3.3.2-18, the applicant stated that, for elastomer flexible hoses exposed to a fuel oil internal environment, there is no aging effect and no AMP is proposed. The AMR line items cite generic note G. The GALL Report does not address elastomeric materials exposed to fuel oil.

Issue:

Given that certain elastomers such as natural rubbers and ethylene-propylene-diene (EPDM) are not resistant to fuel oil, the staff needs to know the material of construction of the flexible hoses to determine if there are no aging effects.

Request:

State the materials of construction for the flexible connections exposed to fuel oil as listed in LRA Tables 3.3.2-18. If the flexible hoses are constructed of a material that is not resistant to fuel oil, propose an aging management program or state the basis for why no aging management program is necessary.

STPNOC Response:

After further evaluation, it was determined that the elastomer flexible hoses are constructed of nitrile, which is not resistant to the fuel oil environment over the long term. In lieu of managing the aging of these flexible hoses, they will be periodically replaced based on vendor recommendations. The flexible hoses will be short lived and will not require aging management.

LRA Table 3.3.2-18 will be revised to remove the entries for elastomer flexible hoses exposed to fuel oil, and to remove "G" from the list of Standard Notes. LRA Table 2.3.3-18 will be revised to remove the component type "Flexible Hoses". LRA Section 3.3.2.1.18 will be revised to remove "Elastomer" from the list of materials, and to remove "Hardening and loss of strength" from the list of aging effects requiring management.

Enclosure 2 provides the line-in/line-out revision to LRA Section 3.3.2.1.18 and LRA Tables 2.3.3-18 and 3.3.2-18.

Electrical Insulators-Conductors (080)

RAI 3.6-1

Background:

The SRP-LR, Revision 2, states that reduced insulation resistance due to presence of surface contamination could occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed. The staff noted during the audit that STP experienced a number of instances of flashover events early in plant life due to lime deposits from heavy dust . The large build up of contamination may enable the conductor voltage to track along the surface more easily and can lead to insulator flash over. The applicant conducted frequent wash-downs of insulators to reduce occurrences of flashover. The applicant also uses silicone insulator coatings to eliminate the flashover events and conducts visual inspections during walk downs to ensure the effectiveness of the silicon coatings. However, the applicant stated in the STP LRA that surface contamination is not an applicable aging effect requiring management for high-voltage insulators at STP.

Issue:

Surface contamination could be a potential aging effect of high-voltage insulators. Reduced insulator resistance due to the presence of surface contamination may enable the conductor voltage to track along the surface more easily and can lead to insulator flash-over.

Request:

Explain why walk down activities to inspect the high-voltage insulator silicon coatings are not considered aging management of insulators. In addition, explain why the high-voltage insulator silicone coating will remain effective for the period of extended operation and why an aging management program is not needed.

STPNOC Response:

The walkdowns referred to in LRA Section 3.6.2.2.2 are part of the switchyard preventive maintenance activities. Centerpoint Switchyard Maintenance conducts weekly and monthly visual inspections within the switchyard. These walkdowns include visual inspection of the insulators for signs of flaking of the silicon coating.

The silicon coating applied to the insulators is a consumable that is replaced as required based on the results from the preventive maintenance activities. The silicon coating was initially applied during construction to minimize dust buildup and eliminate insulator flashovers. With the completion of construction, there has been no occurrence of insulator flashover due to dust. Additionally, the plant is located in an area that receives sufficient rainfall that periodically washes contamination buildup from the insulators.

Since the silicon coating is a consumable and considered short-lived, aging management per NEI 95-10 is part of the switchyard preventive maintenance activities.

Heat Exchangers (085)

RAI 3.3.2.2.4-1

Background:

The acceptance criterion in SRP-LR Section 3.3.2.2.4, item 1, states that cracking due to SCC is managed by monitoring and controlling primary water chemistry, but states that the effectiveness of water chemistry control programs should be verified, because water chemistry controls do not preclude cracking due to SCC and cyclic loading. The GALL Report recommends that a plant-specific AMP be evaluated to ensure these aging effects are adequately managed, and that an acceptable verification program includes temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes. LRA Section 3.3.2.2.4, item 1, states that cracking due to SCC and cyclic loading in stainless steel non-regenerative heat exchanger components is managed by the Water Chemistry Program, and that the effectiveness of the Water Chemistry Program will be confirmed by the One-Time Inspection Program, which includes selected components at susceptible locations. The LRA states that the One-Time Inspection Program was selected in lieu of eddy-current testing of tubes to confirm that cracking is not occurring.

Issue:

LRA Section B2.1.16, "One-Time Inspection," states that selecting piping and components within the material-environment groups for inspection is based on criteria provided in the one-time inspection procedure. However, it is not clear whether the non-regenerative heat exchangers will be included in the sample of components to be inspected; and, since eddy current testing is not used, what inspection techniques will be used.

Request:

(1) Clarify if the non-regenerative heat exchangers will be included in the sample of components to be inspected by the One-Time Inspection Program.

(2) Provide technical justification for not using eddy current testing to confirm that cracking is not occurring in heat exchanger tubes. Provide details on the alternate inspection technique that will detect cracking in the heat exchanger tubes to verify the effectiveness of Water Chemistry Program.

STPNOC Response:

(1) The Chemical and Volume Control System non-regenerative heat exchanger tubes are included in the material/environment component population in the One-Time Inspection Program. LRA Basis Document AMP XI.M32, One-Time Inspection Program does not require that the non-regenerative heat exchanger tubes be specifically selected for inspection. Inspection sample sizes are based on the number of components in a group sharing the same material, environment and aging effects.

(2) LRA Basis Document AMP XI.M32, One-Time Inspection Program, Scope of Program will be revised to add a specific requirement to eddy current the tubes in one of the non-

regenerative heat exchangers. LRA Section 3.3.2.2.4.1 will be revised to include eddy current inspection of the tubes in one of the non-regenerative heat exchangers as part of the One-Time Inspection Program.

Enclosure 2 provides the line-in/line-out revision to LRA Section 3.3.2.2.4.1.

RAI 3.4.2.2.4-1

Background:

SRP-LR 3.4.2.2.4, item 1, is associated with LRA Table 3.4.1, item 3.4.1.9, and addresses stainless steel and copper heat exchanger tubes exposed to treated water which will be managed for reduction of heat transfer due to fouling by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection programs manage loss of heat transfer due to fouling for copper alloy components exposed to secondary water.

Issue:

In its review of components associated with item 3.4.1-9, the staff noted that LRA Table 3.4.2-6 addresses stainless steel heat exchangers (AF turbine oil cooler) in secondary water environment, which will be managed by the Water Chemistry and One-Time Inspection programs for reduction of heat transfer due to fouling; however, the staff did not find any AMR line items for copper alloy heat exchangers.

Request:

Clarify that LRA Section 3.4.2.2.4.1 applies to stainless steel heat exchangers and confirm if there are copper alloy heat exchangers in treated water environment with an aging effect of reduction of heat transfer in steam and power conversion systems.

STPNOC Response:

The AF Turbine Oil Cooler components are stainless steel. There are no copper alloy heat exchanger components in the steam and power conversion systems. LRA Sections 3.4.2.2.4.1 and 3.4.2.2.4.2 inadvertently refer to copper alloy heat exchanger components exposed to secondary water and lubricating oil.

LRA Section 3.4.2.2.4.1 will be revised to change copper alloy to stainless steel heat exchanger components exposed to secondary water. LRA Section 3.4.2.2.4.2 will be revised to change copper alloy to stainless steel heat exchanger components exposed to lubricating oil.

Enclosure 2 provides the line-in/line-out revision to LRA Sections 3.4.2.2.4.1, 3.4.2.2.4.2.

RAI 3.4.2.2.4-2

Background:

SRP-LR 3.4.2.2.4, item 2, is associated with LRA Table 3.4.1, item 3.4.1.10, and addresses steel, stainless steel, and copper heat exchanger tubes exposed to lubricating oil which will be managed by the Lubricating Oil Analysis and One-Time Inspection programs for reduction of heat transfer due to fouling. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Lubricating Oil Analysis and One-Time Inspection programs manage loss of heat transfer due to fouling for copper alloy components exposed to lubricating oil.

Issue:

In its review of components associated with item 3.4.1-10, the staff noted that LRA Table 3.3.2-9 addresses stainless steel heat exchangers (lube oil cooler), and LRA Table 3.4.2-6 addresses stainless steel heat exchangers (AF turbine oil cooler) in lubricating oil environment, which will be managed by the Lubricating Oil Analysis and One-Time Inspection programs for reduction of heat transfer due to fouling; however, the staff did not find any AMR line items for copper alloy heat exchangers.

Request:

Clarify that LRA Section 3.4.2.2.4.2 applies to the above stainless steel heat exchangers, and confirm if there are copper alloy heat exchangers in a lubricating oil environment with an aging effect of reduction of heat transfer in steam and power conversion systems.

STPNOC Response:

There are no copper alloy heat exchanger components in treated water environments in steam and power conversion systems. LRA Section 3.4.2.2.4.1 will be revised to state:

> The Water Chemistry Program (B2.1.2) and the One-Time Inspection Program (B2.1.16) will manage loss of heat transfer due to fouling for stainless steel components exposed to secondary water. The one-time inspection will include selected components at susceptible locations where contaminants could accumulate (e.g. stagnant flow locations).

Enclosure 2 provides the line-in/line-out revision to LRA Section 3.4.2.2.4.1.

RAI 3.3.2.4-1

Background:

SRP-LR Table 2.1-3 states that both the pressure boundary and heat transfer functions for heat exchangers should be considered because heat transfer may be a primary safety function of these components. The staff noted that it provided this clarification of the SRP-LR to the industry by letter dated November 19, 1999. In addition, the GALL Report, Section IX.F, "Aging

Mechanisms," states that fouling can be categorized as particulate fouling from dust, and that fouling can result in a reduction of heat transfer.

Issue:

In its review of heat exchanger-related AMR line items, the staff noted that the LRA listed multiple components in multiple systems with an intended function of heat transfer, but did not include reduction of heat transfer as an aging affect requiring management for these components. The LRA was not consistent, in that some of the above noted heat exchangers in treated borated water and closed cooling water environments are being managed for reduction of heat transfer whereas others are not. In addition, heat exchangers with an intended function of heat transfer in various air environments are not being managed for reduction of heat transfer, which may be adversely affected by fouling due to dust.

Request:

For those heat exchanger-related line items in the LRA that list an intended function of heat transfer, but do not consider reduction of heat transfer as an aging effect requiring management, provide the technical bases demonstrating that reduction of heat transfer does not need to be managed for each of these components.

STPNOC Response:

A review of LRA screened components with a heat transfer intended function found cases where the aging effect of reduction of heat transfer was inadvertently omitted. LRA Tables 3.3.2-6, 3.3.2-19, and 3.3.2-20 will be revised to add the reduction of heat transfer aging effect for the affected heat exchanger components.

A reduction of heat transfer aging effect was not used for heat exchangers with environments of plant indoor air, ventilation atmosphere, or dry gas. The plant indoor air and ventilation atmosphere heat exchanger components are located inside plant buildings that are subject to a clean air environment. Outside air is filtered prior to entry into the affected buildings. The building clean air environment is not considered conducive to heat exchanger fouling and accumulation of dust on heat exchanger surfaces. The dry gas environment is associated with chiller internal refrigerant gas. Dry gas internal to a closed system is not conducive to heat exchanger fouling.

Enclosure 2 provides the line-in/line-out revision to LRA Tables 3.3.2-6, 3.3.2-19, and 3.3.2-20.

Structures (087)

RAI 3.5.2.2.1-1

Background:

SRP-LR Section 3.5.2.2.1.4 addresses loss of material due to general, pitting and crevice corrosion for steel elements of accessible and inaccessible areas of containments. The GALL

Report recommends further evaluation if the following four the GALL Report, item II.A1-11 conditions cannot be satisfied:

(1) Concrete meeting the specifications of ACI 318 or 349 and the guidance of ACI 201.2R was used for the containment concrete in contact with the embedded containment shell or liner.

(2) The concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner.

(3) The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Code Section XI, Subsection IWE requirements.

(4) Water ponding on the containment concrete floor is not common, and is cleaned up in a timely manner when detected.

In addition, several other SRP-LR sections (e.g. 3.5.2.2.1.10 and 3.5.2.2.2.2.2) state that further evaluation is unnecessary if the concrete was constructed in accordance with ACI 318 or the recommendations of ACI 201.2R.

Issue:

The staff agrees that conditions (2), (3), and (4) were addressed adequately by the applicant; however, the LRA did not specify that condition (1) was met. The LRA stated that concrete structures were designed and constructed in accordance with ACI and ASTM standards and that concrete mixes were designed in accordance with ACI 211.1. However, the LRA did not clearly explain how the referenced standards compared to ACI 318 and ACI 201.2R.

Request:

Explain how the ACI and ASTM standards referenced in the LRA meet the intent of ACI 201.2R or ACI 318. The response should cover containment concrete in contact with the embedded steel liner and all other concrete within the scope of license renewal.

STPNOC Response:

The GALL identifies ACI 318 and ACI 349 as acceptable standards for concrete design. The concrete structures other than the containment building are designed in accordance with ACI-318 (Ref. UFSAR Table 3.12-1, Note 33). The code used in the design of the containment is ASME-ACI 359 (ref. UFSAR 3.8.1.2.1). ASME-ACI 359 is a standard produced by a joint committee combining input from ACI Committee 349 and the ASME Boiler and Pressure Vessel Code Committee. This joint standard was developed specifically to address the design and construction of safety-related concrete containment structures and incorporates the applicable requirements of ACI 349.

ACI 201.2R describes specific types of concrete deterioration and discusses the mechanisms involved. It provides recommendations for selecting components of concrete mixes, quality considerations, and construction procedures. ACI 211.1 describes methods for selecting and adjusting proportions for concrete mixes, taking into consideration the requirements for placeability, consistency, strength, and durability. ACI 201.2R references ACI 211.1 for the specifics of designing concrete mixes, and ACI 211.1 references ACI 201.2R for further discussion of potential aging effects. UFSAR Section 3.8.1.6.1.2 references ACI 211.1 for selection and adjustment of concrete mix proportions. Since the requirements in ACI 201.2R are incorporated into ACI 211.1 by reference, the applicable requirements are addressed in the concrete designs.

RAI 3.5.2.3.11-1

Background:

For stainless steel exposed to water, the GALL Report lists cracking due to SCC as a possible aging effect and recommends appropriate aging management techniques, as summarized in GALL AMP XI.M32, "One-Time Inspection."

Issue:

LRA Table 3.5.2-11 lists stainless steel supports in a submerged environment and does not include cracking as an applicable aging effect.

Request:

Justify why cracking is not an applicable aging effect for submerged stainless steel supports or include an appropriate AMP to manage cracking in submerged stainless steel supports. If an AMP is credited with managing this aging effect, provide a technical justification for the credited aging management technique (i.e. inspection method, frequency, etc.).

STPNOC Response:

GALL Chapter IX.D specifies the temperature threshold for stress corrosion cracking (SCC) in stainless steel as 140 F. The stainless steel supports in a submerged environment listed in LRA Table 3.5.2-11 are located in the essential cooling water structures. The water temperature in these structures does not exceed 140 F; therefore, SCC is not an aging effect requiring management for these components.

Non-Metallic (092)

RAI 3.1.2.3.2-1

Background:

LRA Tables 3.1.2-2, 3.2.2-3, 3.3.2-19, 3.4.2-1, 3.4.2-3, and 3.4.2-5 include items for fiberglass and calcium silicate insulation exposed to plant indoor air. The applicant stated that there are no aging effects for these material-environment combinations requiring aging management, and that no aging management program is proposed. In LRA Section 2.1.4.1, the applicant stated that for systems where it has an intended function, insulation was considered within the scope of license renewal and subject to AMR, and is included as a component type in each appropriate in-scope system. The applicant also stated that insulation has an intended function of "insulate," which is defined in Table 2.1-1 as controlling heat loss. UFSAR Section 5.2.3.2.3 states that "The thermal insulation used on the reactor coolant pressure boundary is either reflective stainless steel type or made of compounded materials which yield low leachable chloride and/or fluoride concentrations."

Issue:

The staff notes that in a dry environment of indoor or outdoor air, without potential for water leakage, spray, or condensation, fiberglass and calcium silicate are expected to be inert to environmental effects. However, in moist environments, calcium silicate has been found to degrade. In addition, both fiberglass and calcium silicate insulation have the potential for prolonged retention of any moisture to which they are exposed; prolonged retention of moisture may increase thermal conductivity, thereby degrading the insulating characteristics, and could accelerate the aging of insulated components. The staff noted that for each of the above tables, there is an item for either aluminum or stainless steel material with an insulation function and exposed to the plant indoor air environment. It would appear that these items are jacketing for the insulation; however, it is not clear to the staff all in-scope insulation is protected by jacketing materials or how the insulation is installed such that water intrusion is prevented.

Request:

For LRA Tables 3.1.2-2, 3.2.2-3, 3.3.2-19, 3.4.2-1, 3.4.2-3, and 3.4.2-5, state whether all of the fiberglass or calcium silicate insulation is covered by jacketing, and what procedure requirements are in place so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams) such that aging management is not required.

STPNOC Response:

Plant specifications require most of the insulation in LRA Tables 3.1.2-2, 3.2.2-3, 3.3.2-19, 3.4.2-1, 3.4.2-3, and 3.4.2-5 to be jacketed. The configuration of installed jacketing is in accordance with the plant specifications. External surfaces monitoring procedures require monitoring of the external surfaces of piping within the scope of license renewal every outage. External surfaces monitoring walkdowns will detect component leakage that could negatively impact insulation. If leakage is detected corrective actions are initiated to address the leak and any structures, components, or insulation that has been affected by fluid leakage.

For Chemical and Volume Control, Feedwater, Main Steam and Steam Generator Blowdown systems, and portions of the residual heat removal system piping outside of containment, insulated surfaces are totally covered by protective jacketing or a surface finish, with a few exceptions. Exceptions include areas not normally visible and not likely to receive physical abuse or environmental damage and reactor coolant pressure boundary penetrations. Water is prevented from intruding into the insulation as follows:

- Aluminum jacketing for piping shall have a 2-inch overlap.
- Longitudinal joints on horizontal runs of pipe shall be lapped downward with joint located approximately 45 degrees off the bottom to shed water. Joints in vertical runs of pipe shall have the upper section of jacket overlap the lower section.
- Aluminum jacketing for equipment shall have overlapping edges to allow a completely drainable surface.
- All condensation prevention insulation shall have a jacket with a vapor barrier.

- Where jacket penetrations occur on the upper surface of jacketed outdoor piping, metal shields shall be installed to shed water away from the penetration. Jacket penetrations on the bottom surfaces and sides, and all penetrations with metal shields, shall be sealed with a waterproof caulking.

For systems inside containment, including the Reactor Coolant System and Residual Heat Removal system, the insulation installation specification requires the following measures to prevent water intrusion into the insulation:

- Jacketing shall be provided on hot piping in selected areas where it is required to protect the insulation from leakage.
- Permanent jacketing shall be provided on all piping supplied with condensation prevention insulation.
- Joints between adjacent sections of removable jacketing shall be designed to shed water and keep each section in place.
- The installation contractor is required to demonstrate the water shedding capabilities of jacketing as it is to be installed.

The measures for identifying and correcting leakage coupled with the measures taken in design of the insulation and jacketing provide reasonable assurance that water intrusion into insulation will not lead to degradation of insulation characteristics or accelerated aging of insulated components.

RAI 3.3.2.3.19-1

Background:

In LRA Table 3.3.2-19, the applicant stated that, for a thermoplastic tank exposed to plant indoor air, there is no aging effect and no AMP is proposed.

Issue:

The staff could not confirm that no credible aging effects are applicable for this component, material, and environment combination because there are many material types called "thermoplastics," with variable aging effects when exposed to environments such as ultraviolet light, high radiation, ozone, or chemical species.

Request:

State the specific material of construction for the thermoplastic tank listed in LRA Table 3.3.2-19. State whether there are external environmental factors in the vicinity of the component, such as ultraviolet light, high radiation, temperature, ozone, or chemical species. If these factors could contribute to aging, state the aging effect and the basis for not managing the aging. Alternatively, if external environmental factors could contribute to aging, propose an aging management program to manage the aging effect.

STPNOC Response:

The thermoplastic tanks in LRA Table 3.3.2-19 are zinc acetate solution tanks. The tanks are fabricated from polyethylene and are located in an area of the plant that is not exposed to ultraviolet light, radiation, ozone, or extreme temperatures. The external surface of the tanks is not exposed to chemical species. Thus, based on the material and environment, the external surfaces of the tanks will have no aging effects.

RAI 3.3.2.3.24-1

Background:

LRA Table 3.3.2-24 includes an item for PVC piping exposed to raw water. In the LRA, the applicant states that there are no aging effects for this material and environment combination requiring aging management and no aging management program is proposed. The staff noted that PVC piping exposed to raw water is not addressed in the GALL Report. LRA Table 3.0-1, Mechanical Environments, states that, "Floor drains and building sumps may be exposed to a variety of untreated water that is classified as raw water for the determination of aging effects. Raw water may contain contaminants, including oil and boric acid, as well as originally treated water that is not monitored by a chemistry program."

Issue:

Based on current industry research and operating experience related to PVC piping and piping components, the staff has determined that the factors related to passive aging that may contribute to the degradation of thermoplastics (e.g., PVC, PVDF) include chemical degradation through hydrolysis, and oxidation reactions with a solvent. The staff noted that the raw water environment in the floor drains could include contaminants such as oil and boric acid, which could have a deleterious effect on thermoplastics from a chemical or oxidation reaction.

Request:

State the specific type of PVC piping exposed to raw water in LRA Table 3.3.2-24. State whether this piping could be exposed to contaminants such as oil and boric acid, or other environmental factors that could result in aging effects. State the basis for why there are no aging effects needing management based on the environmental factors for which the piping is exposed, or provide an aging management program to adequately manage the aging effect.

STPNOC Response:

The PVC piping in LRA Table 3.3.2-24 that is exposed to raw water is the drain lines for the control room air-handling units (AHU). The potential fluid in these drain lines results from condensation from the AHU cooling coils, but the GALL states "Condensation on the surfaces of systems at temperatures below the dew point is considered "raw water" due to the potential for internal or external surface contamination." The internal environment of the control room air handling units is required to be free of chemicals that could contaminate the control room. Therefore, it is expected that condensation on the interior of these AHU's would not contain contaminants such as oil, boric acid, or other environmental factors that could result in aging effects.

Engineering Materials Handbook, Volume 2 on Thermoplastics by ASM International lists a variety of aging effects for thermoplastics that are not significant for these drain lines. The aging effects of creep, stress relaxation, yielding and fatigue failure are for thermoplastics under pressure and stress that perform a structural function. The drain lines are at atmospheric temperature and pressure, and do not support structural loads. For moisture-related failures, the Handbook states "while attack by aqueous solutions of acids, alkalis, or oxidants is common, chemical attack of structural plastics by water itself is somewhat rare". Organic chemical-related failure may occur when plastics are exposed to liquids such as cleaning fluids, detergents, gasoline, lubricants, and sealants that may result in the degradation of a plastic's mechanical properties. The most serious problems from this aging mechanism occur when the thermoplastic is exposed to aggressive fluids while under stress. The AHU drain lines are not expected to be exposed to aggressive fluids, and if they were, the lines have low structural and pressure loading, and therefore low resultant stress. Photolytic degradation occurs when plastics are used outdoors and exposed to sunlight. These drain lines are not exposed to sunlight and will not undergo photolytic degradation.

Because it is expected that the environment of the drain lines will be close to pure condensation, GALL Rev. 2 Item VII.J.AP-269 is considered relevant. This GALL item indicates that there are no anticipated aging effects for PVC with an internal condensation environment. In addition, a review of these PVC drain lines against the aging effects listed in Engineering Materials Handbook, Volume 2 on Thermoplastics indicates the potential aging effects for these lines are not significant and do not require management with an aging management program.

Plant Indoor Air (098A)

RAI 3.0-1

Background:

LRA Table 3.0-1 states that the plant indoor air environment encompasses the GALL Report defined environments of "air-indoor controlled," "air-indoor uncontrolled," "condensation," "air, moist," and "air with steam or water leakage."

Issue:

The staff identified a number of Table 2 items for which there are no specified aging effects when exposed to "air-indoor controlled." However, the staff also identified that these same Table 2 items would have aging effects if they were exposed to "air-indoor uncontrolled," "condensation," "air, moist," or "air with steam or water leakage," as defined by the GALL Report. It is unclear to the staff if the components with an environment of plant indoor air are exposed to these potentially adverse environments. Without this information, the staff cannot evaluate whether the proper aging effects and aging management programs are being applied to manage components for which the environment is listed as plant indoor air.

Request:

Identify which AMR items in the LRA are exposed to a plant indoor air environment for which humidity, condensation, moisture, or contaminants are present. If in identifying these items it is determined that there are aging effects requiring management, propose an AMP to manage the aging effect or state the basis for why no AMP is required.

STPNOC Response:

GALL AMR lines VII.J-1 and VII.J-20 for air - indoor controlled (external) were inadvertently selected for 42 components with an external environment of air - indoor uncontrolled.

LRA Tables 3.3.2-4, 3.3.2-17, 3.3.2-19, 3.3.2-20, and 3.3.2-21 will be revised to specify an external environment of air - indoor uncontrolled for 38 aluminum components. These changes will not change the aging effects and aging management which will remain none and none, respectively.

LRA Table 3.3.2-27 will be revised to specify an external environment of air - indoor uncontrolled for four carbon steel components. This change will result in a change to the aging effects and aging management which will be loss of material and aging management program B2.1.20, External Surfaces Monitoring.

Enclosure 2 provides the line-in/line-out revision to LRA Tables 3.3.2-4, 3.3.2-17, 3.3.2-19, 3.3.2-20, and 3.3.2-21, and 3.3.2-27

Stainless Steel (098B)

RAI 3.5.1.59-1

Background:

GALL AMP XI.S3. "ASME Section XI, Subsection IWF," covers the inspection criteria for ASME Code Class 1, 2, and 3 component supports for license renewal and recommends visual inspection of a sample of supports.

LRA Table 3.5.2-11 includes AMR items for stainless steel ASME Class 1, 2, and 3 supports exposed to borated water leakage and plant indoor air which have no AERM assigned and no AMP proposed. The AMR items reference LRA Table 3.5.1, item 3.5.1-59. However, the staff has identified that these supports appear to be within the scope of ASME Code Section XI, Subsection IWF.

Issue:

The staff has identified examples of ASME Class 1, 2, and 3 supports in LRA Table 3.5.2-11 that appear to be within the scope of ASME Code Section XI, Subsection IWF; but have been inappropriately identified as having no AERM. As a result, the ASME-required inspections of these supports may not be performed.

Request:

Identify whether there are any ASME Class 1, 2, or 3 supports within the scope of license renewal which are not being managed by the ASME Code Section XI, Subsection IWF Program. Provide justification for why the supports are not being managed using the ASME Code Section XI, Subsection IWF Program; or provide an appropriate program to manage the aging effects.

STPNOC Response:

STPNOC will provide a response to this RAI by December 8, 2011.

Stainless Steel (O98C)

RAI 3.3.2.3.17-1

Background:

LRA Tables 3.3.2-17, 3.3.2-27, 3.4.2-4, and 3.4.2-6 include AMR line items for stainless steel components (closure bolting, hatch, piping, tank, tubing, valve) exposed to outdoor air (atmosphere/weather) which state that there are no aging effects and no aging management program is recommended. Most of these items cite generic note G, indicating that the environment is not in the GALL Report for the component and material combination.

The GALL Report, Revision 2, and the SRP-LR, Revision 2, state that under some environmental conditions (e.g., exposure to halides and condensation) cracking due to stress corrosion cracking and loss of material due to pitting and crevice corrosion could occur in stainless steel components exposed to outdoor air. The GALL Report and the SRP-LR also recommend that an evaluation be performed based on plant environmental conditions to determine whether aging effects need to be managed for this material and environment combination.

Issue:

The staff noted that for some specific AMR line items (i.e., LRA Table 3.4.2-6, item referring to plant-specific note 3) an evaluation of environmental conditions appears to have been performed. However, it is not clear to the staff that this evaluation has been performed for all in-scope stainless steel components exposed to outdoor air (atmosphere/weather) for which no aging effects are identified.

Request:

Provide an evaluation based on environmental conditions as recommended in the GALL Report, Revision 2, and the SRP-LR, Revision 2, to document the basis for concluding that stainless steel components exposed to outdoor air (atmosphere/weather) have no aging effects requiring management or provide an appropriate program to manage loss of material and cracking for these components.

STPNOC Response:

The prevailing outdoor air at STP is not an aggressive halide rich environment. The plant is not within five miles of a saltwater coastline, there are no roads treated with salt in the winter within 1/2 mile of the plant, the soil does not contain more than trace chlorides, there are no chlorine treated water sources nearby, and the outdoor environment is not subject to industry pollution. The closest industrial facility is 4.8 miles away. The land adjacent to the plant is open range for cattle and farming. There are no large concentrations of cattle within five miles of the plant that could generate excessive detrimental gases or concentrated solid waste. There is no runoff from the adjacent land onto the plant site. Local rain tends to wash the outside surfaces of components rather than concentrate contaminates. A review of the plant operating experience found no occurrences of aging of stainless steel exposed to the outdoor environment. Therefore stainless steel components exposed to an outdoor air environment at STP have no aging effects requiring management.

Steel-Other (100)

RAI 3.3.1.92-01

Background:

LRA Table 3.3.2-17 includes an AMR item for a galvanized carbon steel damper exposed to ventilation atmosphere (internal) in the fire protection system. The AMR item is linked to LRA Table 3.3.1, item 3.3.1-92 (galvanized steel piping exposed to uncontrolled indoor air), which states that there is no aging effect requiring management and no AMP is recommended.

The staff noted that there are similar AMR items for galvanized carbon steel dampers in LRA Tables 3.3.2-10, 3.3.2-11, 3.3.2-12, 3.3.2-14, and 3.3.2-15. For these similar items with similar environments to those listed in Table 3.3.2-17, the LRA states that loss of material is a potential aging effect and the aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. These items are associated with Table 3.3.1, item 3.3.1-72 (steel ducting components exposed to condensation).

The LRA definition of ventilation atmosphere includes condensation and condensation with surface contaminants.

Issue:

It is not clear to the staff why the galvanized carbon steel damper in LRA Table 3.3.2-17 is managed differently than AMR items in Tables 3.3.2-10, 3.3.2-11, 3.3.2-12, 3.3.2-14, and 3.3.2-15 with identical component, material, and environment combinations.

The LRA does not provide sufficient information for the staff to determine whether the galvanized carbon steel damper is exposed to a moist or dry air environment; therefore, the staff cannot determine whether the applicant has appropriately evaluated all of the credible aging effects for this component.

Request:

For the galvanized carbon steel damper exposed to ventilation atmosphere (internal) in LRA Table 3.3.2-17, provide the basis for the determination that this component has no aging effects requiring management during the period of extended operation.

STPNOC Response:

GALL AMR Line VII.J-6 was inadvertently selected for galvanized carbon steel dampers exposed to ventilation atmosphere in the diesel generator building. LRA Table 3.3.2-17 will be revised to specify GALL AMR line VII.F4-2 and B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components for aging management of galvanized carbon steel dampers exposed to ventilation atmosphere (internal).

Enclosure 2 provides the line-in/line-out revision to LRA Table 3.3.2-17.

RAI 3.3.1.96-1

Background:

Updated staff guidance in SRP-LR, Revision 2, Table 3.3-1, item 112 (the GALL Report, Revision 2, item VII.J.AP-282) recommends that steel piping, piping components, and piping elements exposed to concrete do not need to be age-managed, provided that plant operating experience indicates no degradation of the concrete. If this condition is not met, the SRP-LR recommends that a further evaluation be performed to determine whether aging management of steel components embedded in concrete is needed.

The LRA includes carbon steel and galvanized carbon steel components encased in concrete that do not reflect the updated staff guidance in Revision 2 of the SRP-LR. These items are associated with LRA Table 3.3.1, item 3.3.1-96 (SRP-LR, Revision 1, Table 3.3-1, item 96) and state that there are no aging effects requiring management, and that there is no recommended aging management program.

Issue:

The staff needs additional information to complete its evaluation of carbon steel and galvanized carbon steel components encased in concrete to determine whether there has been any concrete degradation that may have exposed steel components to water and thus have subjected the components to corrosion. Affected systems include, but are not limited to, the electrical auxiliary building and control room HVAC system, radioactive vents and drains system, and containments, structures, and component supports system.

Request:

For carbon steel and galvanized carbon steel components encased in concrete, state whether there has been any degradation of concrete in the vicinity of the embedded components such that the components would be exposed to water and thus be subject to corrosion. If such concrete degradation has occurred, state what further evaluation has or will be performed to determine whether aging management of steel components embedded in concrete is needed, consistent with the updated guidance in Revision 2 of both the SRP-LR and the GALL Report. If aging management of these components is needed, propose an appropriate aging management program. If aging management is not needed, provide an appropriate justification.

STPNOC Response:

The Structures Monitoring Program (B2.1.32), which includes the inspection of water-control structures, provides aging management for the concrete in which carbon steel and galvanized carbon steel components are encased. None of the inspections have identified any degradation of the concrete greater in size than a hairline crack. (Ref. RAI B2.1.32-03) All of the hairline cracks were evaluated and determined not to have any impact on the ability of the structure to perform its intended function, including protection of embedded steel components. The Structures Monitoring Program (B2.1.32) will continue to monitor the concrete, and any aging effects that might occur in the future will be managed to ensure that there is no loss of intended function.

Stress-Corrosion cracking (101)

RAI 3.1.2.2.16.1-1

Background:

The GALL Report, item IV.A2-11, recommends AMP XI.M2, "Water Chemistry," and AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWO" to manage cracking due to SCC and primary water stress corrosion cracking (PWSCC) of stainless steel and nickel alloy control rod drive head penetration pressure housing. Examination Category B-O, Item No. B14.20 in Table IWB-2500-1 of the ASME Code Section XI, 2004 edition with no addenda states that volumetric or surface examinations shall be applied for welds in control rod drive (CRD) housings.

LRA Table 3.1.1, item 3.1.1-34 addresses cracking due to SCC and PWSCC of stainless steel and nickel alloy reactor control rod drive head penetration pressure housing, which are managed by the Water Chemistry Program (LRA Section B2.1.2) and Inservice Inspection Program (LRA Section B2.1.1). LRA item 3.1.1-34 states that this aging effect's further evaluation is addressed in LRA Section 3.1.2.2.16.1, "Cracking due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking."

LRA Section 3.1.2.2.16.1 states that, for managing cracking due to SCC for stainless steel components exposed to reactor coolant, the Water Chemistry Program (LRA Section B2.1.2) is augmented by the ASME Code Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program (LRA Section B2.1.1). LRA Section B2.1.1 states that the applicant's ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is consistent with ASME Code Section XI 2004 Edition with no addenda.

Specifically, LRA Table 3.1.2-1 states that following stainless steel components are subject to LRA item 3.1.1-34 and LRA Section 3.1.2.2.16.1: (1) reactor vessel (RV) control rod drive mechanism (CRDM) housing; (2) RV exit thermocouple penetration housing; (3) RV internal disconnect device housing; (4) reactor vessel water level indication system (RVWLIS) upper probe housing; (5) RV CRDM head penetrations (flange and plug); and (6) RV CRDM head penetrations (thermal sleeve).

Issue:

LRA Section B2.1.1 does not address what inspection methods and examination categories are used to manage cracking due to SCC of the following stainless steel components: (1) RV exit thermocouple penetration housing; (2) RV internal disconnect device housing; (3) reactor vessel water level indication system (RVWLIS) upper probe housing; (4) RV CRDM head penetrations (flange and plug); and (5) RV CRDM head penetrations (thermal sleeve). In addition, LRA Section 3.1.2.2.16.1 does not include the RV CRDM housing in the description of the components managed for cracking due to SCC and PWSCC.

Request:

1. Revise LRA Section 3.1.2.2.16.1 in order to include the RV CRDM housing in the LRA section consistent with LRA item 3.1.1-34.

2. Describe the inspection methods and examination categories that the applicant's ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will use to manage cracking due to SCC of the following stainless steel components: (1) RV exit thermocouple penetration housing, (2) RV internal disconnect device housing, (3) reactor vessel water level indication system (RVWLIS) upper probe housing, (4) RV CRDM head penetrations (flange and plug), and (5) RV CRDM head penetrations (thermal sleeve).

In addition, provide justification as to why the inspection methods are adequate to manage cracking due to SCC of these components.

As part of the response, describe how the plug of the "RV CRDM head penetrations (flange and plug)" component is installed (for example, welded or threaded connection to the penetration flange) in order to clarify whether or not the plug is attached directly to the reactor vessel head as a result of the repair of the CRDM penetration nozzles and to determine the adequacy of the inspection methods for this component.

STPNOC Response:

1. LRA Section 3.1.2.16.1 will be revised to change "CRDM head penetrations" to "CRDM penetrations and housings"

2. The ASME Section XI ISI program provides reactor vessel head volumetric and surface examinations of the (1) RV exit thermocouple penetration housing, (2) RV internal disconnect device housing, (3) reactor vessel water level indication system (RVWLIS) upper probe housing, (4) RV CRDM head penetrations (flange and plug), and (5) RV CRDM head penetrations (thermal sleeve).

   ASME Section XI, IWB-2500-1, Examination Category B-O, provides volumetric or surface examination of 21 of the peripheral control rod drive mechanism (CRDM) rod travel housing to latch housing welds and CRDM latch housing to head adapter welds, four of the peripheral core exit thermocouple nozzle assembly head adapter to core exit thermocouple housing welds, and three internal disconnect device penetration to head adapter welds.

   ASME BP&V Code Case N-729-1 provides examinations of the Unit 1 and Unit 2 reactor vessel heads. The code case requires a visual examination of the vessel heads every third refueling outage or every 5 years, whichever is less. This is a bare metal visual examination covering 100% of the intersection of each nozzle with the head. If welded or bolted obstructions are present (i.e. mirror insulation, insulation support feet, etc.), the examination covers at least 95% of the area in the region of the nozzles. The examination will identify indications of leakage caused by stress corrosion cracking. The code case also requires that all nozzles in the head must undergo volumetric and surface examination every 10 year ISI interval.

   These ASME Code examinations are industry accepted methods that have proven to be effective for identifying SCC in the reactor vessel head penetrations.

   In addition to the ASME code inspections, the boric acid corrosion program (B2.1.4) includes provisions for monitoring the RCS for leakage during ISI pressure testing. If indications of leakage are found, each indication is evaluated and dispositioned through the corrective action program. The program also requires a visual inspection to identify potential boric acid leaks above the head, which would identify leakage from the RVWLIS upper probe housing and CRDM flanges.

   The original STP reactor vessel heads had a number of capped CRDM latch housings to allow for the addition of CRDMs to accommodate plutonium recycling in the fuel cycle. The CRDM head penetration plugs in LRA Table 3.1.2-1 were CRDM latch housings capped with a canopy seal welded threaded plug. However, the replacement for the Unit 1 and 2 reactor vessel heads do not have capped latch housings. The CRDM flanges on the replacement heads are full penetration butt welded. The ASME Section XI ISI program will manage cracking of these CRDM flange butt welds with the ASME Section XI, IWB-2500-1, Category B-O inspections.

Enclosure 2 provides the line-in/line-out revision to LRA Section 3.1.2.16.1.

RAI 3.1.2.2.16.1-2

Background:

The GALL Report, Revision 2, item IV.D1.RP-385, states that GALL AMP XI.M2, "Water Chemistry," manages cracking due to PWSCC of steam generator tube-to-tubesheet welds made of nickel alloy. The GALL Report, item IV.D1.RP-385, also states that a plant-specific program is evaluated to confirm the effectiveness the water chemistry program and to ensure that cracking is not occurring.

SRP-LR, Revision 2, Section 3.1.2.2.11, item 2, states that cracking due to PWSCC could occur in steam generator nickel alloy tube-to-tubesheet welds exposed to reactor coolant and that, unless an NRC-approved pressure boundary definition excludes the tube-to-tubesheet weld, the effectiveness of the primary water chemistry program should be verified to ensure that cracking is not occurring.

LRA Section 3.1.2.2.16.1, "Steam Generator Heads, Tubesheets, and Welds Made or Clad with Stainless Steel," and LRA item 3.1.1-35 state that the applicant has recirculating steam generators, not once-through steam generators, so cracking due to stress corrosion cracking and primary water stress corrosion cracking is not applicable. The applicant's AMR items for the steam generator components, which are described in LRA Table 3.1.2-4, do not address how the applicant manages cracking due to PWSCC of steam generator tube-to-tubesheet welds exposed to reactor coolant.

LRA Section B2.1.8 states that the STP steam generators were replaced with Westinghouse Delta 94 steam generators in 2000 and 2002 for Units 1 and 2, respectively. LRA Section B2.1.8 also states that the STP replacement steam generators are equipped with Alloy 690TT tubes.

Issue:

The LRA omits aging management consistent with the GALL Report, Revision 2, item IV.D1.RP-385, to manage cracking due to PWSCC of steam generator tube-to-tubesheet welds made of nickel alloy.

Request:

Describe the materials that were used for the fabrication of the steam generator tubesheet cladding and the tube-to-tubesheet welds.

1. Describe how cracking due to PWSCC of the steam generator nickel alloy tube-to-tubesheet welds will be managed for the period of extended operation. If the applicant proposes a one-time inspection to manage cracking due to PWSCC of these components, describe the plant-specific operating experience in terms of the occurrence of PWSCC of the tube-to-tubesheet welds.

   In addition, if the operating experience indicates that the components have experienced cracking due to PWSCC, justify why the proposed use of a one-time inspection rather than periodic inspections is adequate to manage the aging effect.

2. If the applicant has determined that the materials used for the fabrication of the steam generator tubes, tubesheet cladding and tube-to-tubesheet welds are not susceptible to cracking due to PWSCC, (1) provide the technical basis for the determination and (2) describe how the applicant will evaluate future industry and plant-specific operating experience regarding the PWSCC of the tube-to-tubesheet welds in order to identify and conduct necessary corrective actions for these components.

3. Revise the LRA consistent with the applicant's response, including LRA item 3.1.1-35 and Section 3.1.2.2.16.1.

STPNOC Response:

1. The tube plate of the steam generators is low alloy steel that is clad with weld deposited nickel chromium iron alloy (UNS N06052 and W86152). The steam generator tubes are fabricated of Alloy 690 (UNS N06690). The tubes are welded directly to the tube plate cladding, and no welding rod is used. Industry operating experience has not shown primary water stress corrosion cracking (PWSCC) in Alloy 690/52/152 materials. Likewise industry research has shown these alloys to be highly resistant to PWSCC.

2. GALL Report, Revision 2, item IV.D1.RP-385 addresses PWSCC in Nickel Alloy components, but industry experience has shown that unlike lower chromium content Nickel Alloys 600/82/182, higher chromium content Nickel Alloys 690/52/152 are highly resistant to PWSCC. As STP's steam generator tubes and tubesheets are fabricated from the PWSCC resistant alloys, the Water Chemistry (B2.1.2) program is considered adequate to manage PWSCC in these components. Therefore, it is not currently necessary to manage PWSCC of the steam generator tube to tubesheet welds with a plant specific program. South Texas Project's commitment to review industry operating experience will ensure that if PWSCC becomes an issue in 690/52/152 alloys, it will be managed appropriately.

3. No LRA changes are required based on the response provided above. LRA Item 3.1.1-35 and further evaluation 3.1.2.2.16.1 pertain to once-through steam generators. The STP recirculating steam generators are managed using LRA Items 3.1.1.72 and 3.1.1.73.

RAI 3.5.2.2.1.7-1

Background:

The GALL Report, item II.A3-2, states that the containment penetration sleeves and bellows, made of stainless steel and dissimilar metal welds, are subject to cracking due to stress corrosion cracking in the air-indoor uncontrolled or air-outdoor environment. The GALL Report states that the aging effect of these components is managed by GALL AMPs XI.S1, "ASME Section XI, Subsection IWE" and XI.S4, "10 CFR Part 50, Appendix J." In addition, the GALL Report states that further evaluation should be performed to evaluate the detection of aging effects.

LRA Section 3.5.2.2.1.7, "Cracking due to SCC," which is associated with LRA Table 3.5.1, item 3.5.1-10, addresses cracking due to SCC in stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds. LRA Section 3.5.2.2.1.7 also states that for LRA item 3.5.1-10, cracking due to SCC is not an aging effect requiring management for STP stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. The applicant further stated that both high temperature (>140°F) and exposure to an aggressive environment are required for SCC to be applicable and at STP, these two conditions are not simultaneously present for any stainless steel penetration sleeves, bellows, or dissimilar metal welds. In addition, the applicant stated that review of STP plant-specific operating experience did not identify any stress corrosion cracking of these components.

In comparison, LRA Table 3.5.2-1 addresses the applicant's aging management for containments, structures, and component supports. LRA Table 3.5.2-1 indicates that stainless steel containment penetrations and bellows are exposed to plant indoor air and are subject to cracking due to stress corrosion cracking. LRA Table 3.5.2-1 and LRA Table 3.5-1, item 3.5.1-10, indicate that the applicant credited the ASME Code Section XI, Subsection IWE Program and 10 CFR 50, Appendix J Program to manage this aging effect.

During a walk-down for the structures and associated components conducted as part of the aging management program audit, the staff noted the applicant has operating experience with groundwater in-leakage and accumulation in the area between the fuel handling building and the containment building of both Units. The staff noted that this environmental condition can contribute to the occurrence of stress corrosion cracking of these components.

Issue:

The staff noted that the applicant's aging management review results described in LRA Tables 3.5-1 and 3.5.2-1 are in conflict with the applicant's claim described in LRA Section 3.5.2.2.1.7 that cracking due to stress corrosion cracking is not applicable for the stainless steel containment penetration components (sleeves, bellows and dissimilar metal welds). The staff further noted that the LRA does not provide the applicant's evaluation of the operating experience regarding potential exposure of the penetration components to groundwater in-leakage and accumulation even though currently the containment structures are experiencing groundwater in-leakage and accumulation.

In addition, the AMR items for the containment penetration components in LRA Table 3.5.2-1 do not include dissimilar metal welds in the material description columns.

Request:

1. Describe the plant-specific operating experience with groundwater in-leakage and accumulation in order to clarify whether or not the containment penetration components have been exposed to the groundwater. If the containment penetration components have been in contact with the leaked groundwater, justify why the exposure of the components to the groundwater is not conducive to stress corrosion cracking of the stainless steel components, taking into account the potential for the contamination of the leaked groundwater with corrosive species (such as chlorides).

2. Resolve the conflict between the aging management review (AMR) results in LRA Section 3.5.2.2.1.7 and the AMR results in LRA Tables 3.5-1 and 3.5.2-1 in order to clarify whether or not cracking due to stress corrosion cracking is applicable to the stainless steel

penetration components. In addition, provide a technical basis for the applicant's determination on the applicability of stress corrosion cracking to these components.

3. If cracking due to stress corrosion cracking is applicable to the containment penetration components, justify why the use of the AMSE Code Section XI, Subsection IWE Program and the 10 Part 50, Appendix J Program, without the additional augmented inspection recommended in the GALL Report, is adequate to detect and manage the aging effect.

4. Describe how the applicant will evaluate the future operating experience to identify and perform any necessary corrective action for ensuring that the intended functions of these components are maintained. As part of the response, clarify whether or not the applicant's evaluation of future operating experience will include the inspection and test results of the AMSE Code Section XI, Subsection IWE Program and the 10 Part 50, Appendix J Program.

5. Justify why dissimilar metal welds are not included in the material description columns of the AMR items for the containment penetration components in LRA Table 3.5.2-1. In addition, revise the LRA consistent with the applicant's response.

<u>STPNOC Response:</u>

1. The groundwater in-leakage between the fuel handling building and the containment building is in an area with a floor elevation of (-)29' and has accumulated to a depth of 6 or 7 ft. (See RAI B2.1.32-06). The lowest containment penetration is in the emergency sump at an elevation of (-)15'-3". Therefore, no containment penetrations have been exposed to this groundwater.

2. Cracking due to stress corrosion cracking (SCC) is not an aging effect that is expected to occur for South Texas Project (STP) stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. The temperature threshold for SCC in stainless steel is 140 F (Ref. GALL, Chapter IX.D). The normal operating temperature inside the containment building is limited to 120 F (Ref. UFSAR Table 9.4-1). Exposure to an aggressive environment is also required for SCC to be applicable. At STP, the environment inside the containment is non-aggressive. The sealed containment prevents contact with uncontrolled outside air, and procedural controls limit which substances may be brought into containment. Review of STP plant-specific operating experience did not identify any SCC of stainless steel containment penetration sleeves, bellows, and dissimilar metal welds.

   However, the fuel transfer tube and associated expansion bellows are part of the containment pressure boundary. As such, they are within the scope of license renewal under the ASME Section XI, Subsection IWE program (B2.1.27) and the 10 CFR 50, Appendix J program (B2.1.30). As discussed above, SCC is not expected to occur under the conditions present at STP, but these aging management programs will continue to monitor these components to confirm the absence of aging effects. It is not necessary to augment the IWE visual examinations with additional surface examinations, because Appendix J testing can be performed on these components. As stated in GALL (Rev. 2), Chapter XI.S1, Element 4, "Where feasible, Appendix J tests may be performed in lieu of the surface examination."

   LRA Section 3.5.2.2.1.7 will be revised to add the following paragraph:

However, the fuel transfer tube and associated expansion bellows are part of the containment pressure boundary. As such, they are within the scope of license renewal under the ASME Section XI, Subsection IWE program (B2.1.27) and the 10 CFR 50, Appendix J program (B2.1.30). As discussed above, SCC is not expected to occur under the conditions present at STP, but these aging management programs will continue to monitor these components to confirm the absence of aging effects.

Enclosure 2 provides the line-in/line-out revision to LRA Section 3.5.2.2.1.7.

3. As discussed above, SCC is not expected to occur under the conditions present at STP. However, STP will continue to monitor the fuel transfer tube and associated expansion bellows under the ASME IWE program and the Appendix J program (B2.1.30). It is not necessary to augment the IWE visual examinations with additional surface examinations, because Appendix J testing can be performed on these components. As stated in GALL (Rev. 2), Chapter XI.S1, Element 4, "Where feasible, Appendix J tests may be performed in lieu of the surface examination."

4. As stated in the response to RAI B1.4 Reference STPNOC letter NOC-AE-11002716, Operating experience is applied to all aging management programs discussed in LRA Section A1 and A2. Plant-specific and industry operating experience is continuously reviewed to confirm the effectiveness of aging management programs and is utilized, as necessary, to enhance each aging management program or to develop new aging management programs in order to adequately manage the effects of aging so that the intended function(s) of structures and components are met.

   Any plant-specific condition that is found to be outside of the applicable acceptance criteria is evaluated in the corrective action program. As part of this evaluation, a determination is made of any potential impact that the unacceptable condition might have on the performance of any intended function, including those of the containment components subject to the inspections and testing of the AMSE Code Section XI, Subsection IWE Program and the 10 Part 50, Appendix J Program.

5. Component types Bellows and Penetration with material Stainless Steel shown in LRA Table 3.5.2-1 are aligned with GALL line II.A3-2. These components include the dissimilar metal welds. II.A3-2 is applicable to both stainless steel and dissimilar metal welds. LRA Section 3.5.2.1.1 and Table 3.5.2-1 will be revised to clarify that the material for the bellows and penetrations includes both stainless steel and dissimilar metal welds.

   Enclosure 2 provides the line-in/line-out revision to LRA Section 3.5.2.1.1 and LRA Table 3.5.2-1.

Identification of Time-Limited Aging Analyses (TLAAs) (058)

<u>RAI 4.1-2</u> (Absence of TLAA for the Containment Liner Plates)

<u>Background:</u>

License renewal application (LRA) Section 4.6 states that the applicant's review of the current licensing basis (CLB) did not identify any fatigue analyses for the containment liner plates or containment equipment hatches. LRA Section 4.6 states that the original specification for procurement of the containment liner indicated that fatigue was to be evaluated per NE-3222.4 and NE-3131(d) of the American Society of Mechanical Engineers (ASME) Code Section III, and that the 1974 Edition of ASME Code Section III, Division 1, Subsection NE, subparagraph NE-3222.4, provides the rules for performing fatigue analyses of metal containment (MC) components, which includes subparagraph NE-3222.4(d) provisions on when a given MC component could be waived from the mandated fatigue analysis requirements.

LRA Section 4.6 also states that the containment liners were designed in accordance with the specifications in Bechtel Specification BC-TOP-1 and the design requirements in the 1973 Edition of ASME Code Section III, Division 2, inclusive of Addenda 1 through 6 of the Code.

The staff also noted that the applicant indicated that its search of CLB documents did not identify any fatigue analyses of record for the South Texas Project (STP) metal containment liners.

<u>Issue:</u>

There is an inconsistency or gap in the information provided in LRA Section 4.6 concerning the design requirements for the containment liners. In one part of the section, the applicant indicates that the containment liners were designed, procured, and installed to Bechtel Specification BC-TOP-1 specifications and to the 1973 ASME Code Section III requirements. However, in another part of this LRA section, the applicant indicates that the liners were to be procured to the requirements in the 1974 Edition of ASME Code Section III, including the fatigue analysis requirements in ASME Code Section III, subparagraph NE-3222.4. In addition, the applicant does not make any statement or provide any discussions on whether a fatigue exemption (waiver) analysis had been performed for the containment liners under the provisions of ASME Code Section III, subparagraph NE-3222.4(d). In addition, STP UFSAR Section 3.8.1.5.9 states that the cyclic stresses and strains in the containment liners are considered in performing a fatigue analysis. Thus the staff has difficulty in understanding why the containment liners would not have been designed and procured to the requirements in the 1974 edition of ASME Code Section III, as stated in the LRA, or why appropriate fatigue analyses would not have been required for these liners under the requirements of the 1974 Edition of the ASME Code Section III, Subparagraph NE-3222.4.

<u>Request:</u>

Clarify which edition of the ASME Code Section III, Subarticle NE-3000 was used for the design of the containment liner, and if the 1973 edition is the appropriate ASME Code Section code of record, explain why subparagraph NE-3222.4 in the 1974 Edition of the code would not have been applied to containment liners when the owner's procurement specification would have called for its use. Consistent with this response, justify why an NE 3222.4 subparagraph-required fatigue analysis was not performed for the containment liners under the appropriate ASME Code Section III, design rules. With respect to this response, clarify whether the containment liners had been exempted (waived) from a fatigue analysis under provisions of NE-3222.4(d), and if so, justify why the fatigue waiver analysis would not need to be identified as a TLAA for the LRA when compared to the fatigue waiver analysis for the personnel and emergency (auxiliary) air locks, which was identified as a TLAA for the application.

STPNOC Response:

The STP containment liner is not designed to ASME Code Section III, Subarticle NE-3000. UFSAR Section 3.8.2 for Steel Containment Components (ASME Class MC Components) states:

> This section, as outlined in the NRC format regarding a "Steel Containment", is not applicable to the STPEGS Containment structure itself, since a steel-lined, post-tensioned concrete Containment is used, as described in Section 3.8.1.1.

UFSAR Section 3.8.1.2 describes the design codes to which the containment and the liner plate are designed as ASME Section III, Division 2 issued for trial use and comment in 1973, including Addenda 1 through 6. The NRC approved the methodology of BC-TOP-5-A as an acceptable means to meet these requirements. BC-TOP-5-A references the methodology of BC-TOP-1 for design of the liner plate. This design method compares the stresses specified in BC-TOP-1, which are independent of the number of load cycles, and have no fatigue analyses. In general, the design of metallic liners is not fatigue controlled, since most stress and strain changes occur only a small number of times and/or produce only minor stress-strain fluctuations.

RAI 4.1-3 (Absence of TLAA for RPV Underclad Cracking)

Background:

LRA Table 4.1-2 and LRA Section 4.7.4 state that the applicant's review of the CLB did not identify any time dependent flaw growth, flaw tolerance, or fracture mechanics evaluations in assessment of reactor pressure vessel (RPV) underclad cracks. The applicant states that, although there is an applicable Westinghouse Topical Report that assesses fatigue flaw growth analysis in RPV underclad cracks, the report is not being applied as part of STP CLB for managing the potential for underclad cracks to in the welds that are used to join the cladding to the RPV forging components that are made from SA-508, Class 2 materials. The applicant stated that instead, its design basis uses the application of Regulatory Guide (RG) 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Component" [May 1973], as the basis for precluding or mitigating the occurrence of underclad cracks in the SA-508 RPV forging-to-cladding welds.

The staff verified in STP Updated Final Safety Analysis Report (UFSAR) Section 5.2.3.3.2, that the applicant is crediting the basis in RG 1.43. This UFSAR section states that all welding at STP is conducted utilizing procedures that are qualified in accordance with the applicable weld qualification rules of the ASME Code Sections III and IX, and that control of welding variables, as well as examination and testing during procedure qualification and production welding, is performed in accordance with the applicable ASME Code requirements. UFSAR Section 5.2.3.3.2 also states that Westinghouse (as the NSSS vendor of the STP RPV) meets the intent of RG 1.43 by requiring qualification of any high-heat input welding process (e.g., submerged arc wide-strip welding process or a submerged-arc-6-wire welding process) used on SA-508 Class 2 material, with a performance test as described in regulatory position 2 of the RG 1.43. However, another section of the UFSAR (i.e. UFSAR Section 5.3.1.2) indicates that the referenced procedure qualification was to be accompanied with a special evaluation in order to assure freedom from the underclad cracking phenomenon.

Issue:

LRA Section 4.7.4 only refers to the use of RG 1.43 and the applicability of the information in UFSAR Section 5.2.3.3.2. LRA Section 4.7.4 does not make any reference to the "special evaluation" that is referenced in UFSAR Section 5.3.1.2 for the evaluation of RPV underclad cracking. In order to understand the complete basis described in LRA Section 4.7.4, the staff needs clarification regarding what was done in the CLB or current design basis to satisfy the STP UFSAR Section 5.3.1.2 protocol for performing the special evaluation mentioned in the UFSAR section. If such a "special evaluation" was implemented as part of the CLB or design basis, the basis in LRA Section 4.7.4 should also assess how the "special evaluation" compares to the six criteria for TLAAs in 10 CFR 54.3, and justify whether it needs to be identified as a TLAA for the LRA under the requirements of 10 CFR 54.21(c)(1).

Request:

Discuss and clarify how the applicant fulfilled the STP UFSAR Section 5.3.1.2 protocol for performing the "special evaluation" mentioned in the UFSAR section, and summarize what the special evaluation involved, along with an appropriate CLB or design basis reference. If such a “special evaluation” was implemented as part of the CLB or design basis, clarify how the “special evaluation” compares to the six criteria for TLAAs in 10 CFR 54.3, and justify whether or not the “special evaluation" should be identified as a TLAA for the LRA under the TLAA identification requirements of 10 CFR 54.21(c)(1). Otherwise, if the "special evaluation" was not implemented as part of the CLB or current design basis, clarify how conformance with RG 1.43 was accomplished in the design basis without the implementation of the "special evaluation" and justify why the "special evaluation" would not need to be implemented as part of the design basis in order to demonstrate conformance with the regulatory position in RG 1.43 (i.e., contrary to the design basis statement that is currently given in UFSAR Section 5.3.1.2) and that underclad delaminations (i.e., underclad cracking) in the RPV SA-508 forging-to-cladding welds would be adequately prevented or mitigated as an applicable aging effect and mechanism during the period of extended operation using the RG 1.43 conformance basis.

STPNOC Response:

UFSAR Section 5.2.3.3.2 provides the “special evaluation” cited in UFSAR Section 5.3.1.2. It determined that the intent of RG 1.43 is met by requiring qualification of any high heat input process, such as the submerged-arc wide-strip welding process and the submerged-arc-6-wire process used on SA-508 Class 2 material, with a performance test as described in regulatory position 2 of the guide. No qualifications are required by the RG for SA-533 and equivalent chemistry for forging grade SA-508 Class 3 materials.

A review of the welding qualification test requirements in regulatory position 2 does not indicate that the tests account for an aging mechanism or are time-dependent; therefore, the "special evaluation" is not a TLAA in accordance with 10 CFR 54.3(a) Criteria 2 and 3.

RAI 4.1-4 (Absence of TLAA for the Turbine-Driven AFW Pump Supply Piping)

Background:

LRA Table 4.1-2 identifies that the applicant's review of the CLB did not identify any time-dependent fatigue analyses for the main steam supply lines to the turbine-driven auxiliary feedwater (AFW) pumps. Therefore, the applicant states that LRA does not need to include a fatigue TLAA for these lines because the generic "fatigue analysis for the main steam supply lines to the turbine-driven auxiliary feedwater pumps" in SRP-LR Table 4.1-3 is not applicable to STP's CLB.

UFSAR Table 10.1-1 indicates that each STP unit is designed with three (3) motor-driven AFW pumps and one (1) turbine driven AFW pump. UFSAR Table 3.2.A-1 indicates that the main steam supply lines to the turbine-driven AFW pump were designed to either ASME Code Section III, Subarticle NC or ND design requirements for ASME Code Class 2 or 3 components.

GALL AMR VIII.B1-10 identifies that cumulative fatigue damage/fatigue may be an aging effect requiring management for steel main steam piping that is exposed to a steam or secondary water environment and recommends that a TLAA be credited to manage this aging effect during the period of extended operation.

Issue:

The staff has verified that the ASME Code Section III, design code of record (1974 Edition inclusive of the Winter 1975 Addenda) did not require explicit CUF or I_t fatigue analyses of these main steam supply lines. However, the ASME Code Section III, Subarticle NC or ND requirements may have required the applicant to perform a maximum allowable stress range reduction analysis for the main steam supply lines to the turbine-driven AFW pump. In addition, LRA Section 4.3.5 identifies the maximum allowed stress range reduction analyses for the ASME Code Class 2 and 3 piping as TLAAs for the LRA. Thus, the staff is of the opinion that the applicant needs to provide further clarification and justification on why the maximum allowed stress range reduction TLAA discussed in LRA Section 4.3.5 would not be applicable to the main steam supply lines that supply steam to the turbine-driven AFW pump during a turbine-driven AFW pump actuation.

Request:

Clarify with supporting justification whether cumulative fatigue damage (or "cracking-fatigue") is an applicable aging effect requiring management (AERM) for the main steam supply lines to the turbine-driven AFW pump. If cumulative fatigue damage (or "cracking-fatigue") is an applicable AERM for these lines, provide the basis on why maximum allowable stress range reduction TLAA in LRA Section 4.3.5 would not be identified as the appropriate TLAA for managing cumulative fatigue damage or "cracking-fatigue" in these lines consistent with GALL AMR

VIII.B1-10 recommendations, and why the main steam lines to the turbine-driven AFW pump would not need to be within the scope of the maximum allowable stress range reduction analysis TLAA that is given in LRA Section 4.3.5.

STPNOC Response:

The main steam supply lines to the turbine-driven AFW pump were analyzed using a stress range reduction factor to implicitly analyze for cumulative fatigue damage. These lines are included in the scope of the lines evaluated in LRA Section 4.3.5. As noted in response to RAI 4.3-18, the AMR lines for these components were omitted from the LRA. LRA Table 3.4.2-1 will be revised to add an AMR line for the main steam supply lines to the turbine-driven AFW pump.

Enclosure 2 provides the line-in/line-out revision to Table 3.4.2-1.

RAI 4.1-5 (Absence of TLAA for Flow-Induced Vibrations)

Background:

LRA Table 4.1-2 and LRA Section 4.3.3 state the applicant's review of the CLB did not identify any time-dependent flow-induced vibration endurance limit analyses for the reactor vessel internals (RVI) components. The applicant states that the CLB does not describe any time-limited effects for a licensed operating period associated with flow-induced vibration, and that, therefore, there are not any TLAAs associated with flow-induced vibrations of the RVI components, when assessed against the TLAA definition criteria in 10 CFR 54.3(a), Criteria 2 and 3.

The STP flow-induced vibration analysis basis for RVI components is accounted for in the following sections and Tables of the UFSAR:

- Section 3.9.2.3, "Dynamic Response Analysis of Reactor Internals Under Operational Flow Transients and Steady-State Conditions"
- Section 3.9.2.4, "Preoperational Flow-Induced Vibration Testing of Reactor Internals"
- Section 3.9.2.6, "Correlations of Reactor Internals Vibration Tests with the Analytical Results"
- Section 1.6, "Material Incorporated By Reference," and Table 1.6-2, "Westinghouse Topical Reports Incorporated By Reference" - with the following WCAP Reports invoked by reference as part of the flow-induced vibration analysis basis:
    - Proprietary U.S. Nuclear Regulatory Commission {NRC)-Approved WCAP-8303-P-A, Revision 0, "Prediction of the Flow-Induced Vibration of Reactor Internals by Scale Model Tests"
    - Proprietary NRC-Approved WCAP-8516-P-A, Revision 0, "UHI Plant Internals Vibration Measurement Program and Pre and Post Hot Functional Examinations"

- Proprietary NRC-Approved WCAP-8766-P-A, Revision 0, "Verification of Neutron Pad and 17 x 17 Guide Tube Designs by Preoperational Tests on the Trojan 1 Power Plant"

- Proprietary WCAP-9395-P, "4XL Scale Model Internal Flow Test Structural Response Test" -(UFSAR Section 1.5 indicates that this WCAP includes an assessment of the vibrational levels in the internals)

- WCAP-9646, "Verification of Upper Head Injection Reactor Vessel Internals by Preoperational Test of the Sequoyah Power Plant"

- Proprietary WCAP-10865, "South Texas Plant (TGX) Reactor Internals Flow-Induced Vibration Assessment"

Collectively, these UFSAR sections and tables indicate that the applicant uses conformance with the NRC's position in Regulatory Guide (RG) 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," as the basis for protecting the integrity of the RVI components against those aging effects that may be induced by flow-induced vibrations (e.g., cracking or loss of material by wear induced by the vibrations) and that the applicant uses Indian Point, Sequoyah, and Trojan flow-induced vibration programs and test data as the applicant's prototypical analysis basis for STP.

Issue:

LRA Section 4.3.3 does not provide a comprehensive summary of the total STP basis that is used to assure the integrity of the RVI components from the impacts of flow-induced vibrations. Specifically, the applicant only makes a very general statement that the CLB did not include any flow-induced vibration analyses that would need to be identified as a TLAA for the LRA, and supports this position with a statement that any flow-induced vibration analyses in the CLB either did not involve an assessment of an applicable aging effect (i.e., did not conform to 10 CFR 54.3 Criterion 2) or were not based on time-dependent assumptions defined by the life of the plant (i.e. did not conform to 10 CFR 54.3 Criterion 3). Although LRA Section 4.3.3 does reference the applicability of UFSAR Section 3.9.2.3, it fails to mention that the applicant's flow-induced vibration basis for the RVI components was based on conformance with the NRC position in RG 1.20 or that the flow-induced vibrational bases in UFSAR Sections 3.9.2.4 and 3.9.2.6 are also part of the applicant's RG 1.20 conformance basis. LRA Section 4.3.3 fails to identify which of the WCAP reports in UFSAR Table 1.6-2 (e.g., WCAP-8303-P-A, WCAP-8516-P-A, WCAP-8766-P-A, WCAP-9395-P, WCAP-9646, and WCAP-10865-P) are currently being relied upon as part of the applicant's current RG 1.20 conformance basis, or whether each of the analyses in these WCAP reports would need to be identified as TLAAs when compared to the six criteria for TLAAs in 10 CFR 54.3. LRA Section 4.3.3 also fails to mention that the applicant credits its plant-specific PWR Reactor Internals Program (i.e., LRA AMP B2.1.35) with the management of the aging effects that are applicable to the STP RVI components, including those that could be induced by a flow-induced vibration mechanism (e.g., cracking or loss of material). Thus, without further clarification, the staff is unable to confirm that the LRA would not need to include any TLAAs on flow-induced vibrations of the RVI components.

Request:

Part 1 -Clarify which edition of RG 1.20 is being used as the current basis for assessing flow-induced vibrations of the STP RVI components and provide a brief summary (i.e., clarification) on how the information in UFSAR Sections 3.9.2.3, 3.9.2.4, and 3.9.2.5 relates to the STP RG 1.20 conformance basis and to each other.

Part 2 -Identify which of the WCAPs in UFSAR Table 1.6-2 are currently being relied upon as part of the applicant's RG 1.20 conformance basis, and for those WCAPs that are credited for RG 1.20 conformance, provide a brief summary of all analyses, evaluations, or calculations that were included in each of these WCAP reports (if any) to support the STP RG 1.20 conformance basis and provide an assessment of these analyses, evaluations, or calculations against the TLAA identification criteria in 10 CFR 54.3.

Part 3 -Justify whether each analysis, evaluation, or calculation provided in response to Part 2 needs to be identified as a TLAA for the LRA under the TLAA identification requirements of 10 CFR 54.21(c)(1).

STPNOC Response:

Part 1 - As identified in UFSAR Table 3.12-1, the South Texas Project is committed to RG 1.20 Rev 2 (5/76). As described in UFSAR Section 3.9.2.4 and RG 1.20, Position 1.4, STP is a Non-Prototype, Category I plant. Therefore, the analyses of flow-induced vibration at the prototype plants, i.e. Indian Point No. 2, Trojan and Sequoyah No. 1, and any analysis of the design differences implemented at STP are part of the CLB. UFSAR Section 3.9.2.3 describes the portions of the analyses and tests for the prototype plants that are applicable to STP. UFSAR Section 3.9.2.4 describes STP compliance with RG 1.20 by demonstrating that the design differences have no significant effect on the vibratory response and provides a description of the inspection performed during hot functional testing required by RG 1.20. UFSAR Section 3.9.2.5 does not relate to STP compliance to RG 1.20.

Part 2 & 3 – The WCAPs from UFSAR Table 1.6-2 that are currently being relied upon for conformance to RG 1.20 were determined by cross-referencing UFSAR Table 1.6-2 against the reference for UFSAR Section 3.9 (page 3.9-85).

WCAP-7879 is relied upon for compliance with RG 1.20. The WCAP describes a test program designed to confirm the adequacy of the Indian Point Plant No. 2 pre and post hot functional visual and dye penetrant examinations and measurement of internal vibration and dynamic behavior for the guidetubes, core barrel, and thermal flexures. The report does address high cycle fatigue, but simply calculates a factor of safety by dividing the design allowable by the measured strains. Because stress levels are well below the design allowable for high cycle fatigue, it is concluded internals are free from harmful vibrations. The design allowable is defined as 10^11 cycles. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-7879 is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-8303-P-A (WCAP-8317-NP-A) is relied upon for compliance with RG 1.20. WCAP-8303 describes a 1/24th scale model test program used to simulate the internal of Indian Point No. 2. The purpose of the report is to show the accuracy with which scale model test results predict the flow-induced vibration, caused by either a thermal shield or neutron shielding pads, on full-size reactors core barrel. The report concludes that the natural frequencies, modes shapes, acceleration spectra, and vibration amplitudes agree well with the test result of Indian Point No. 2, and that the vibrational displacements are small. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-8303-P-A is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-8516-P-A (WCAP-8517-NP-A) is relied upon for compliance with RG 1.20. This report describes a test program to be carried out at the TVA Sequoyah No. 1 plant designed to confirm the adequacy of the four-loop, 17x17 Upper Head Injection (UHI) upper internals assembly. The program consists of pre and post hot functional visual examinations and measurement of internal vibration. The report describes the test program and location of the test instrumentation, which is not based on any time-dependent assumptions; therefore, WCAP-8516-P-A is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-8766-P-A (WCAP-8780-NP-A) is relied upon for compliance with RG 1.20. This report compares the results from the Trojan plant internals vibration measurement program to the expected responses for the 17x17 guide tube and neutron pad core barrel. WCAP-8733 concludes that the vibration levels are as expected. The report does address high cycle fatigue in the guide tubes, but simply calculates a factor of safety by dividing the endurance limit by the measured strains. The endurance limit is defined as 10^11 cycles. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-8766-P-A is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-9395-P is relied upon for compliance with RG 1.20. It is not referenced in UFSAR Section 3.9, but is referenced in WCAP-10865. This report provides the mean and vibratory flow-induced responses for the 1/7 scale model of the 4XL reactor internals. Data were obtained on core barrel, support column and guide tube, bottom-mounted instrumentation column responses. The report concludes the strain and displacement levels were low and no instabilities were noted in the behavior. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-9395-P-A is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-9946 is relied upon for compliance with RG 1.20. This report describes the internals vibration measurement and assurance program performed on Sequoyah 1. The purpose of this program was to confirm the expected vibrations of the four loop upper head injection upper internals assembly. For the support columns and the upper guide tube, the resulting stresses were compared to allowable fatigue stresses. Lower guide tube responses were evaluated using structural models and compared to failure levels obtained from a guide tube fatigue test. The report calculates factors of safety by dividing the endurance limit by the measured strains. The endurance limit is defined as 10^11 cycles. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-9946-P-A is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

WCAP-10865 is relied upon for compliance with RG 1.20. It is not referenced in UFSAR Section 3.9, but is cited in UFSAR Section 1.5.3, which ties the WCAP to Section 3.9.2.3, 'Dynamic Response Analysis of Reactor Internals Under Operational Flow Transients and Steady-State Conditions," which is part of how STP demonstrates compliance with RG 1.20. The WCAP determines by comparison that the scale model data and hot functional test results from prototype plants are applicable to STP and it is not considered necessary to conduct instrumented tests of STP. The report concludes that vibration of the internals is well characterized by the existing data from previous plants and scale models, and the vibrational amplitudes and stresses are small. WCAP-10865 does mention fatigue, only to note that the fatigue usage factor is zero and that the stresses are insignificant, i.e. beyond the endurance limit and not affected by the life of the plant. These conclusions are not based on any time-dependent assumptions; therefore, WCAP-10865 is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

<u>RAI 4.1-7</u> (Exemption Identification Followup RAI)

<u>Background:</u>

LRA Section 4.1.4 states that the CLB includes seven exemptions in the CLB that were granted under the provisions of 10 CFR 50.12, and that of these exemptions, the exemption on the LBB analysis (which forms the applicant's basis for complying with "dynamic effect" analysis relaxation provisions in 10 CFR Part 50, Appendix A, General Design Criterion 4) was the only exemption that was based on a TLAA. In the applicant's letter of December 9, 2010, the applicant provided its response to RAI 4.1-1 and identified that the exemption on use of Code Case N-514 should have been identified as an exemption for the LRA that conforms to the exemption identification requirement in 10 CFR 54.21 (c)(2) and amended the application to add the exemption on Code Case N-514 as an exemption that was based on a TLAA RAI 4.1-1 has been resolved based on that LRA amendment.

<u>Issue:</u>

The staff has observed that in LRA Section (AMP) B2.1.15, "Reactor Vessel Surveillance," the applicant mentions that an exemption was granted in the original license from meeting the requirements of 10 CFR Part 50, Appendix H, but did not provide any discussion in the LRA on why this exemption would not need to be identified for the LRA under the criteria on 10 CFR 54.21(c)(2). The staff has also observed that, in STP Letter No. NOC-AE-000518, dated July 13, 1999, the applicant requested NRC approval of numerous risk-informed exemptions from applicable requirements in 10 CFR, as based on the regulatory exemption acceptance provisions of 10 CFR 50.12, and that the applicant failed to make any mention of these risk-informed exemptions in LRA Section 4.1.4. Thus, the staff still has difficulty determining exactly how many exemptions were granted to the applicant under the requirements of 10 CFR 50.12. and of these exemptions, what the exemptions are based upon and how many remain in effect for the CLB and will need to be identified as exemptions that were granted under 10 CFR 50.12 and are based on a TLAA - as mandated by the license renewal application requirement in 10 CFR 54.21(c)(2).

<u>Request:</u>

Part 1 -Provide a list of all exemptions that were granted in the CLB in accordance with the regulatory exemption criteria of 10 CFR 50.12. Of these exemptions, identify the regulation in 10 CFR for which each exemption was requested, and summarize what the exemption involved and whether it remains in effect for the CLB.

Part 2 -Provide the bases, with appropriate justifications, why each of the exemptions discussed in the response to Part 1 would not need to be identified as an exemption for the LRA pursuant to the exemption identification criterion in 10 CFR 54.21(c)(2). Account for the 10 CFR Part 50, Appendix H-based exemption that is referred to in LRA Section B2.1.15 and the risked-informed exemptions that were requested in the applicant's letter of July 13, 1999 (i.e., STP Letter No. NOC-AE-000518) in these responses to RAI 4.1-7, Parts 1 and 2.

<u>STPNOC Response:</u>

1. A search of the current licensing basis identified seven 10 CFR 50.12 exemptions in effect for STP, listed in the table below.

2. There is no record of an exemption from the 10 CFR Part 50, Appendix H requirements. The statement in LRA Section B2.1.15 of an exemption in the program was in reference to footnote "***" on UFSAR page 5.3-4. It notes that the weld coupons are not samples from the actual manufacturing of the vessel, but is "Weld metal identical to heat of wire and lot of flux used to fabricate vessel beltline region intermediate to lower shell girth weld." This does not constitute an exemption from 10 CFR Part 50, Appendix H, which requires that the coupons be representative of the limiting beltline materials.

The risked-informed exemptions that were requested in July 13, 1991 are discussed in Item 7 below.

LRA Section 4.1.4 will be updated to note that this is a 10 CFR 50.12 exemption based on a TLAA.

Enclosure 2 provides the line-in/line-out revision to LRA Section 4.1.4.

Table 1: 10 CFR 50.12 Exemptions Currently in Effect

Description	Evaluation	Ref
1. Exemption from Appendix J, Section III.D.2(b)(ii) requirements for Unit 1 and 2, which requires full pressure testing of the air locks following opening during periods when containment integrity is not required, i.e. Modes 5 or 6. The exemption allows the seal leakage test of paragraph III.D.2 (b) (iii) to be substituted for the full pressure test of paragraph II.D.2 (b) (ii) of Appendix J if no maintenance has been performed on an air lock that could affect its sealing capability.	The exemption demonstrates that if the periodic 6 month test of paragraph III.D.2.(b)(i) of Appendix J and the test required by paragraph III.D.2(b)(iii) of Appendix J are current; no maintenance has been performed on the air lock that could affect its sealing capability; and the air lock was properly sealed, then there is no reason to expect the air lock to leak excessively, even though it has been opened in Mode 5 or Mode 6. This exemption is not based on a TLAA, under 10 CFR 54.3(a) Criteria 2 and3.	Ref. 1

Description	Evaluation	Ref
2. Exemption from 10 CFR 70.24 requirements for criticality monitoring during handling of spent fuel for Units 1 and 2. The exemption allows the handling of spent nuclear fuel without a criticality monitor.	The basis for the exemption is the low probability of a criticality accident together with the adherence to General Design Criteria 63. The low probability of a criticality accident is determined by meeting seven criteria. These seven criteria do not depend on time. This exemption is not based on a TLAA, under 10 CFR 54.3(a) Criterion 3.	Ref. 1
3. Exemption from the requirements of 10 CFR 50.71(e)(4) regarding schedule for submittal of UFSAR revisions for Units 1 and 2.	The UFSAR revision submittal schedule exemption does not involve a TLAA, under 10 CFR 54.3(a) Criteria 2 and 3.	Ref. 2
4. Exemption from the requirements to include the dynamic effects of RCS pipe breaks in the design basis based on leak-before-break (LBB) analysis for Units 1 and 2.	This exemption to allow use of LBB analysis for RCS primary loop piping is based in part on a TLAA of fatigue effects. The LBB analysis was also used in design of the RSGs and RRVCHs. This exemption is based on a TLAA and is addressed in Section 4.3.2.11.	Refs. 1, 3, 4, and 5
5. Exemption from certain requirements of 10 CFR 50.60 and 10 CFR 50, Appendix G, to allow use of ASME Code Case N-514 to establish the LTOP setpoints for Units 1 and 2.	This exemption is discussed more in Section 4.2.5 and is based in part on a TLAA. This exemption is based on a TLAA and is addressed in Section 4.2.5.	Ref. 6
6. Exemption from the requirements of Appendix K and section 50.46 of 10 CFR 50 concerns use of a non- Zircaloy fuel cladding on lead test fuel assemblies.	This exemption is not based on a TLAA, under 10 CFR 54.3(a) Criteria 2 and 3.	Ref. 7
7. Exemption requests partial exclusion from the scope of special treatment requirements of 10 CFR Parts 21, 50, and 100 (Graded QA approach).	These "Non Risk Safety" and "Low Safety Significance" components no longer fall under the scope of 10 CFR 50.49; however the qualifications the safety related components are still part of the CLB and remain within the scope of equipment qualification program. This exemption is based in part on a TLAA and is addressed in Section 4.4. The methodology for determining the risk significance classification is discussed in more detail in response to RAI 4.4-1, Request 3.	Ref. 8

References:
1. USNRC NUREG-0781, Supplement No. 3. Docket No. 50 499, "Safety Evaluation Report Related to the Operation of South Texas Project Units 1 and 2." May 1987.

2. US NRC Letter. Thomas W. Alexion, Project Manager, Section 1, Project Directorate IV 1, Division of Reactor Projects, Office of Nuclear Reactor Regulation; to Mr. William T. Cottle, STP. "Issuance of Exemption to 10 CFR 50.71(e) (4), South Texas Project, Units 1 and 2, (STP) (TAC Nos. MA2496 and MA2497." 2 November 1998 [STP-AE-NOC-000285].

3. USNRC NUREG-0781, Supplement No. 2. Docket No. 50 499, "Safety Evaluation Report Related to the Operation of South Texas Project Units 1 and 2." January 1987.

4. USNRC NUREG-0781, Supplement No. 4. Docket No. 50 499, "Safety Evaluation Report Related to the Operation of South Texas Project Units 1 and 2." July 1987.

5. STP Letter ST-HL-AE-1010. J. H. Goldberg, VP, Nuclear Engineering and Construction, HL&P; to Harold R. Denton, Director, Office of Nuclear Reactor Regulation, USNRC. "Pipe Break Design Considerations." 28 September 1983.

6. US NRC Letter. Thomas W. Alexion, Project Manager, Section 1, Project Directorate IV-1, & Decommissioning, Division of Licensing Project Management, Office of Nuclear Reactor Regulation; to Mr. William T. Cottle, STP. "South Texas Project, Units 1 and 2, Exemption from the Requirements of 10 CFR 50.60 (TAC Nos. MA5065 and MA5066)." 4 May 1999 [ST-AE-NOC-000406].

7. US NRC Letter. From David H. Jaffe, Senior Project Manager, Section1, Project Directorate IV, Office of Nuclear Reactor Regulation, to James J. Sheppard, President and Chief Executive Officer, STP. Units 1 and 2 "Exemption from the Requirements of Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix K and Section 50.46. (TAC Nos. MC3368 and 3369)." 19 October 2004 [ADAMS No. ML042940500].

8. US NRC Letter. From John Zwolinski, Director, Division of Licensing Project Management, Office of Nuclear Reactor Regulation, to William T. Cottle, President and Chief Executive Officer, STP. Units 1 and 2 "Safety Evaluation on Exemption Requests from Special Treatment Requirements of 10 CFR Parts 21, 50, and 100 (TAC Nos. MC6057 and 6058)." 3 August 2001 [ADAMS Nos. ML011990368 and ML012040370].

Enclosure 2 provides the line-in/line-out revision to LRA Section 4.1.4.

RAI 4.4-1, Environmental Qualification of Electric Components (TLAA)

Background:

In LRA Section 4.4," Environmental Qualification (EQ) of Electric Components," the applicant stated that the program is consistent with the guidance of NUREG-588, Category 1, and the requirements of 10 CFR 50.49, with exemption from environmental scope for certain low-safety/risk significant (LSS) and non-risk significant (NRS) components.

10 CFR Part 49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," establishes a program for qualifying the electric equipment (e.g., safety-related electric equipment, non-safety-related electric equipment, and certain post accident monitoring equipment). By letters dated July 13, 1999, as supplemented October 14 and 22, 1999, January 26 and August 31, 2000, and January 15, 18, 23, March 19, May 8 and 21, 2001, (hereinafter, the submittal, Adams accession number ML011430090), STP Nuclear Operating Company requested an exemption from 10 CFR Part 49(b), to exclude LSS/NRS components from the scope of electrical equipment important to safety under 10 CFR 50.49(b).

The staff noted that §54.21 c(2) states that a list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs as defined in §54.3. The applicant is also required to provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

The staff also noted that 10 CFR 54.4(a)(1), states:

> Plant systems, structures, and components within the scope of this part are safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1) to ensure the integrity of the reactor coolant pressure boundary; (and) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or § 100.11 of this chapter, as applicable.

The Statement of Considerations for the 10 CFR 54 final rule, Section III.c(iv), states regarding the use of probabilistic risk assessment in license renewal, that the Commission concluded that it was inappropriate to establish a license renewal scoping criterion that relies on plant-specific probabilistic analyses.

10 CFR Part 54.4, "Scope," requires the following:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1) to ensure the following functions--

- (i) The integrity of the reactor coolant pressure boundary;
- (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
- (iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or § 100.11 of this chapter, as applicable.

(2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire

protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

Issue:

The applicant did not provide the plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs as defined in §54.3 and as applied to 10 CFR 50.49(b). Furthermore, the applicant did not provide any evaluation that justifies the continuation of these exemptions for the period of extended operation. The staff is concerned that an exemption to 10 CFR 50.49(b) for electric equipment important to safety based on probabilistic risk assessment is inconsistent with the license renewal rule statement of considerations and 10 CFR Part 54.4 scoping, which utilizes deterministic criteria. Further, the staff is concerned that these exempted electric components are not included in the scope of license renewal, and therefore not subject to a TLAA or an associated aging management program and therefore, may not be capable of performing their intended function for the period of extended operation.

Request:

1. Provide a list of electrical and instrumentation and control system SSCs that were excluded from the scope of license renewal (10 CFR 54.4 (a)(1), (a)(2), and (a)(3) as a result of special treatment requirements exemption of SSCs.

2. Provide a list of electrical and instrumentation and control system SSCs that have been exempted from 10 CFR 50.49(b), including SSC replacements, subject to 10 CFR 54.4.

3. Indicate whether the electrical and instrumentation and control system components for which the exemption for 10 CFR Part 50.49 was granted, are within the scope of license renewal. If not, provide justification for their exclusion. Include justification for the continuation of these exemptions into period of extended operation.

4. Describe any subsequent modifications or changes to either plant design or LSS/NRS components that revised LSS/NRS electrical and instrumentation and control component environmental conditions or qualification. If so, describe the modifications or changes incorporated into the aging management of the LSS/NRS electrical and instrumentation and control components.

5. Discuss how the specific management program/controls (inspection, tests, and surveillances) are adequate to provide aging management during the period of extended operation such that LSS/NRS electrical and instrumentation and control components are capable of performing their intended function under design basis conditions throughout the service life of the component

STPNOC Response:

1) No components were excluded from the scope of license renewal as a result of special treatment requirements exemption of SSCs (10 CFR 50.69).

2) There are no electrical and instrumentation and control system SSCs, including SSC replacements that have been exempted from 10 CFR 50.49 qualification requirements. The safety/risk significant (LSS) and non-risk significant (NRS) EQ components are treated the same way as non LSS and NRS EQ components with the exception that the documentation requirements for LSS and NRS components are not as stringent to that of non LSS and NRS EQ components. UFSAR Section 13.7 allows LSS and NRS components to not be qualified per 10 CFR 50.49 but as stated above STP has opted to maintain the qualification of the LSS and NRS components.

3) The EQ electrical and instrumentation and control system components classified as LSS or NRS are within the scope of license renewal. No EQ components were excluded from the scope of license renewal as a result of special treatment requirements exemption of SSCs (10 CFR 50.69).

4) Data loggers were installed in containment at selected locations to determine actual temperatures. This data was then used to determine the qualified life of EQ transmitters at those selected locations. The actual temperatures were lower than the design temperature, which provided margin for extending the qualified life. The data gathered was for extending the qualified life of selected transmitters but did not change the design criteria. Design Change Packages were prepared with the new qualified lives.

5) The special exemption components are part of the STP Environmental Qualification (EQ) program. They are treated the same way as any other EQ component with the exception that the documentation requirement is not as stringent as that of a normal EQ component. These components would still follow the replacement dates (Start of Qualified Life (SOQL) and Replacement Due Date (RDD)) as designated under our Qualification Maintenance Database (QMDB).

   UFSAR Sections 13.7.3.3.1 through 13.7.3.3.3 discuss the design, procurement, and installation for safety-related LSS and NRS SSCs. The controls ensure the component is able to perform its safety-related function for its expected life and satisfy 10 CFR Part 50, Appendix B, and other regulatory requirements that may be applicable, such as 10 CFR 50.59.

   UFSAR Section 13.7.3.3.4 discusses the maintenance process for safety-related LSS and NRS SSCs to establish the scope, frequency, and detail of maintenance activities necessary to support STP's determination that these SSCs will remain capable of performing their safety-related functions under design-basis conditions. Preventive maintenance tasks are developed for active structures, systems, or components factoring in vendor recommendations. The frequency and scope of predictive maintenance actions are established and documented considering vendor recommendations, environmental operating conditions, safety significance, and operating performance history.

   UFSAR Section 13.7.3.3.5 discusses the inspection, test, and surveillance process for safety-related LSS and NRS SSCs to obtain data or information that allows evaluation of operating characteristics to support STP's determination that these SSCs will remain capable of performing their safety-related functions under design-basis conditions throughout the service life of the SSC.

The Environmental Equipment Qualification Program provides adequate aging management during the period of extended operation such that LSS/NRS electrical and instrumentation and control components are capable of performing their intended function under design basis conditions throughout the service life of the component.

Enclosure 2

STP LRA Changes with Line-in/Line-out Annotations

List of Revised LRA Sections

RAI 3.3.2.3.22-1	LRA Section 3.3.2.1.22 LRA Section 3.3.2.1.27 LRA Table 3.3.2-22 LRA Table 3.3.2-27
RAI 3.4.2.6-1	LRA Section 3.3.2.1.2 LRA Section 3.3.2.1.9 LRA Section 3.4.2.1.4 LRA Section 3.4.2.1.6 LRA Table 3.3.2-2 LRA Table 3.3.2-9 LRA Table 3.3.2-27 LRA Table 3.4.2-4 LRA Table 3.4.2-6 LRA Appendix A1.6 LRA Appendix B2.1.6
RAI 3.3.2.13-1	LRA Section 3.3.2.1.13 LRA Section 3.3.2.1.15 LRA Table 3.3.2-13 LRA Table 3.3.2-15
RAI 3.5.2.11-1	LRA Section 3.5.2.1.11 LRA Table 3.5.2-11
RAI B2.1.16-3	LRA Appendix B2.1.16.
RAI 4.3-2	LRA Table 4.3-2
RAI 4.3-4	LRA Section 4.3.6 LRA Appendix A3.2.5
RAI 4.3-6	LRA Table 4.3-8
RAI 4.3-9	LRA Section 4.3.3 LRA Appendix A3.2.2
RAI 4.3-13	LRA Table 4.3-2
RAI 4.3-18	LRA Table 3.3.2-8 LRA Table 3.3.2-19 LRA Table 3.3.2-20 LRA Table 3.3.2-21 LRA Table 3.3.2-22 LRA Table 3.4.2-1 LRA Table 3.4.2-2 LRA Table 3.4.2-5 LRA Table 3.4.2-6
RAI 4.3-20	LRA Section 4.3.2.10 LRA Appendix A3.2.1.10
RAI 4.3-22	LRA Section 4.3.2.6 LRA Appendix A3.2.1.6
RAI 3.2.1.50-1	LRA Table 3.3.2-17
RAI 3.1.1.80-1	LRA Section 3.1.2.2.12 LRA Section 3.1.2.2.17 LRA Table 3.1.1 LRA Table 3.1.2-1

RAI 3.3.2.3.10-1	LRA Table 3.3.2-10 LRA Table 3.3.2-20
RAI 3.3.2.3.18-1	LRA Section 3.3.2.1.18 LRA Table 2.3.3-18 LRA Table 3.3.2-18
RAI 3.3.2.2.4-1	LRA Section 3.3.2.2.4.1
RAI 3.4.2.2.4-1	LRA Section 3.4.2.2.4.1 LRA Section 3.4.2.2.4.2
RAI 3.4.2.2.4-2	LRA Section 3.4.2.2.4.1
RAI 3.3.2.4-1	LRA Table 3.3.2-6 LRA Table 3.3.2-19 LRA Table 3.3.2-20
RAI 3.0-1	LRA Table 3.3.2-4 LRA Table 3.3.2-17 LRA Table 3.3.2-19 LRA Table 3.3.2-20 LRA Table 3.3.2-21 LRA Table 3.3.2-27
RAI 3.3.1.92-01	LRA Table 3.3.2-17
RAI 3.1.2.2.16.1-1	LRA Section 3.1.2.2.16.1
RAI 3.5.2.2.1.7-1	LRA Section 3.5.2.1.1 LRA Section 3.5.2.2.1.7 LRA Table 3.5.2-1
RAI 4.1-4	LRA Table 3.4.2-1
RAI 4.1-7	LRA Section 4.1.4

RAI 3.3.2.3.22-1	LRA Sections 3.3.2.1.22 and 3.3.2.1.27 Tables 3.3.2-22 and 3.3.2-27
RAI 3.4.2.6-1	LRA Table 3.3.2-27
RAI 4.3-18	LRA Table 3.3.2-22
RAI 3.0-1	LRA Table 3.3.2-27

3.3.2.1.22 Liquid Waste Processing System

Materials

The materials of construction for the liquid waste processing system component types are:

- Carbon Steel
- Cast Iron
- Copper Alloy
- Glass
- Stainless Steel
- Stainless Steel Cast Austenitic

Environment

The liquid waste processing system component types are exposed to the following environments:

- Borated Water Leakage
- Closed-Cycle Cooling Water
- Demineralized Water
- Dry Gas
- Plant Indoor Air
- Raw Water
- Secondary Water
- ~~Sodium Hydroxide~~
- Steam
- Treated Borated Water

Aging Effects Requiring Management

The following liquid waste processing system aging effects require management:

- Cracking
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the liquid waste processing system component types:

- Bolting Integrity (B2.1.7)
- Boric Acid Corrosion (B2.1.4)
- Closed-Cycle Cooling Water System (B2.1.10)
- External Surfaces Monitoring Program (B2.1.20)
- Flow-Accelerated Corrosion (B2.1.6)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
- One-Time Inspection (B2.1.16)
- Water Chemistry (B2.1.2)

3.3.2.1.27 Miscellaneous Systems In-Scope ONLY based on Criterion 10 CFR 54.4(a)(2)

Materials

The materials of construction for the miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types are:

- Aluminum
- Carbon Steel
- Cast Iron
- Copper Alloy
- Copper Alloy (Aluminum > 8 percent)
- Copper Alloy (Zinc > 15 percent)
- Ductile Iron
- Glass
- Nickel-Alloys
- Polyvinyl Chloride (PVC)
- Stainless Steel

Environment

The miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types are exposed to the following environments:

- Atmosphere/ Weather
- Borated Water Leakage
- Buried
- Closed-Cycle Cooling Water

- Demineralized Water
- Dry Gas
- Plant Indoor Air
- Potable Water
- Raw Water
- Secondary Water
- ~~Sodium Hydroxide~~
- Treated Borated Water

Aging Effects Requiring Management

The following miscellaneous systems in-scope ONLY based on Criterion 10 CFR 54.4(a)(2) aging effects require management:

- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the miscellaneous systems in scope ONLY based on Criterion 10 CFR 54.4(a)(2) component types:

- Bolting Integrity (B2.1.7)
- Buried Piping and Tanks Inspection (B2.1.18)
- Closed-Cycle Cooling Water System (B2.1.10)
- External Surfaces Monitoring Program (B2.1.20)
- Flow-Accelerated Corrosion (B2.1.6)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
- One-Time Inspection (B2.1.16)
- Selective Leaching of Aluminum Bronze (B2.1.37)
- Selective Leaching of Materials (B2.1.17)
- Water Chemistry (B2.1.2)

Table 3.3.2-22 Auxiliary Systems – Summary of Aging Management Evaluation – Liquid Waste Processing System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Carbon Steel	Plant Indoor Air (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-18	3.3.1.02	A
Piping	LBS	Carbon Steel	Secondary Water (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended	VII.E1-16	3.3.1.02	A
Piping	LBS	Carbon Steel	Steam (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended	VIII.B1-10	3.4.1.01	A

Table 3.3.2-22 Auxiliary Systems – Summary of Aging Management Evaluation – Liquid Waste Processing System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, SIA	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-15	3.3.1.79	E, 3
~~Piping~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Piping	LBS, PB, SIA	Stainless Steel	Treated Borated Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-17	3.3.1.91	E, 4

Table 3.3.2-27Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Accumulator	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
~~Accumulator~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Accumulator	LBS	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-15	3.3.1.79	E, 3
Closure Bolting	SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	None	None	H, 1

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Boron Recycle Evaporator)	LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	IV.C2-14	3.1.1.53	B
~~Heat Exchanger (Boron Recycle Evaporator)~~	~~LBS~~	~~Carbon Steel~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-20~~	~~3.3.1.95~~	A
Heat Exchanger (Boron Recycle Evaporator)	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B
Piping	SIA	Aluminum	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	None	None	G

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Carbon Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-19	3.3.1.76	E, 9
Piping	LBS	Carbon Steel	Raw Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	None	None	H, 10
Piping	LBS, SIA	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-11	3.4.1.04	A

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Nickel Alloys	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-13	3.3.1.78	E, 3
~~Piping~~	~~LBS~~	~~Nickel Alloys~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~	~~None~~	~~None~~	~~G~~
Piping	LBS	Polyvinyl Chloride (PVC)	Plant Indoor Air (Ext)	None	None	None	None	F, 6

Piping	LBS, SIA	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.G-32	3.4.1.16	A
~~Piping~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Piping	LBS, SIA	Stainless Steel	Treated Borated Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-17	3.3.1.91	E, 7

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Pump	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
~~Pump~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Sight Gauge	LBS	Glass	Plant Indoor Air (Ext)	None	None	VII.J-8	3.3.1.93	A

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Sight Gauge	LBS	Glass	Plant Indoor Air (Int)	None	None	VII.J-7	3.3.1.93	A
~~Sight Gauge~~	~~LBS~~	~~Glass~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~	~~None~~	~~None~~	~~G~~
Sight Gauge	LBS	Glass	Raw Water (Int)	None	None	VII.J-11	3.3.1.93	A

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Sight Gauge	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Sight Gauge	LBS	Stainless Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	V.A-26	3.2.1.08	E
~~Sight Gauge~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Sight Gauge	LBS	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-15	3.3.1.79	E, 3
Strainer	LBS	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
Strainer	LBS	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-15	3.3.1.79	E, 3
~~Strainer~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Tank	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tank	LBS	Stainless Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	V.A-26	3.2.1.08	E
~~Tank~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Tank	LBS	Stainless Steel	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-15	3.3.1.79	E, 3
Tubing	LBS	Stainless Steel	Borated Water Leakage (Ext)	None	None	VII.J-16	3.3.1.99	A

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B
~~Valve~~	~~LBS, SIA~~	~~Carbon Steel~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-20~~	~~3.3.1.95~~	A
Valve	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B
Valve	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

Table 3.3.2-27 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Nickel Alloys	Plant Indoor Air (Ext)	None	None	VII.J-14	3.3.1.94	A
~~Valve~~	~~LBS~~	~~Nickel Alloys~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~	~~None~~	~~None~~	~~G~~
Valve	LBS	Nickel Alloys	Raw Water (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.C1-13	3.3.1.78	E, 3
Valve	SIA	Stainless Steel	Atmosphere/ Weather (Ext)	None	None	None	None	G
Valve	LBS	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.G-32	3.4.1.16	A
~~Valve~~	~~LBS~~	~~Stainless Steel~~	~~Sodium Hydroxide (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~None~~	~~None~~	~~G, 2~~
Valve	LBS, SIA	Stainless Steel	Treated Borated Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-17	3.3.1.91	E, 7

Notes for Table 3.3.2-27:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F Material not in NUREG-1801 for this component.
G Environment not in NUREG-1801 for this component and material.
H Aging effect not in NUREG-1801 for this component, material, and environment combination.

Plant Specific Notes:
1 Loss of preload is conservatively considered to be applicable for all closure bolting.
2 Operating experience does not suggest there is any aging effect, and the use of stainless steel up to 200°F and 50 weight-percent NaOH is common in industrial applications with no special consideration for aging. There is no NUREG-1801 line that includes NaOH environment.
3 The component environment is radioactive waste drains that have been evaluated as a raw water environment. Loss of material on internal component surface exposed to radioactive waste drains environment is managed by Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22) instead of the Open-Cycle Cooling Water program (B2.1.9).
4 The internal environment of these components is comprised of nonradioactive waste streams which may include oil and other contaminants that are evaluated as raw water. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22) manages this uncontrolled raw water environment rather than the Open-Cycle Cooling Water program (B2.1.9).
5 The external environment of these components is comprised of nonradioactive waste streams which may include oil and other contaminants that are evaluated as raw water. The External Surfaces Monitoring (B2.1.20) manages this uncontrolled raw water environment rather than the Open-Cycle Cooling Water program (B2.1.9).
6 PVC is relatively unaffected by water, concentrated alkalis, and non-oxidizing acids, oils, and ozone.
7 The Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.16) manage loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking. The One-Time Inspection program (B2.1.16) includes selected components at susceptible locations.
8 Loss of material by selective leaching will be managed by Selective Leaching of Aluminum Bronze (B2.1.37) instead of Selective Leaching of Materials (B2.1.17) for components made of aluminum bronze (copper alloy greater than 8 percent aluminum).
9 The internal environment of these components is comprised of raw water. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22) manages this raw water environment more appropriately than Open-Cycle Cooling Water program (B2.1.9).
10 Wall thinning due to erosion-corrosion is managed by the Flow-Accelerated Corrosion program (B2.1.6).

RAI 3.4.2.6-1	LRA Sections 3.3.2.1.2, 3.3.2.1.9, 3.4.2.1.4, 3.4.2.1.6 LRA Tables 3.3.2-2, 3.3.2-9, 3.3.2-27, 3.4.2-4, 3.4.2-6 LRA Appendices A1.6, B2.1.6

(See RAI 3.3.2.3.22-1 for changes to LRA Table 3.3.2-27)

3.3.2.1.2 Spent Fuel Pool Cooling and Cleanup System

Materials

The materials of construction for the spent fuel pool cooling and cleanup system component types are:

- Carbon Steel
- Stainless Steel

Environment

The spent fuel pool cooling and cleanup system component types are exposed to the following environments:

- Borated Water Leakage
- Closed-Cycle Cooling Water
- Plant Indoor Air
- Treated Borated Water

Aging Effects Requiring Management

The following spent fuel pool cooling and cleanup system aging effects require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer
- <u>Wall Thinning</u>

Aging Management Programs

The following aging management programs manage the aging effects for the spent fuel pool cooling and cleanup system component types:

- <u>Flow-Accelerated Corrosion (B2.1.6)</u>
- Bolting Integrity (B2.1.7)
- Closed-Cycle Cooling Water System (B2.1.10)
- External Surfaces Monitoring Program (B2.1.20)

- One-Time Inspection (B2.1.16)
- Water Chemistry (B2.1.2)

3.3.2.1.9 Chilled Water HVAC System

Materials

The materials of construction for the chilled water HVAC system component types are:

- Carbon Steel
- Carbon Steel (Galvanized)
- Cast Iron
- Copper Alloy
- Copper Alloy (> 15 percent Zinc)
- Glass
- Stainless Steel
- Titanium

Environment

The chilled water HVAC system component types are exposed to the following environments:

- Closed-Cycle Cooling Water
- Demineralized Water
- Dry Gas
- Lubricating Oil
- Plant Indoor Air
- Raw Water

Aging Effects Requiring Management

The following chilled water HVAC system aging effects require management:

- Loss of material
- Loss of preload
- Reduction of heat transfer
- <u>Wall Thinning</u>

Aging Management Programs

The following aging management programs manage the aging effects for the chilled water HVAC system component types:

- Flow-Accelerated Corrosion (B2.1.6)
- Bolting Integrity (B2.1.7)
- Closed-Cycle Cooling Water System (B2.1.10)
- External Surfaces Monitoring Program (B2.1.20)
- Lubricating Oil Analysis (B2.1.23)
- One-Time Inspection (B2.1.16)
- Open-Cycle Cooling Water System (B2.1.9)
- Selective Leaching of Materials (B2.1.17)
- Water Chemistry (B2.1.2)

3.4.2.1.4 Demineralizer Water (Make-up) System

Materials

The materials of construction for the demineralized water (make-up) system component types are:

- Carbon Steel
- Copper Alloy
- Stainless Steel

Environment

The demineralized water (make-up) system components are exposed to the following environments:

- Atmosphere/ Weather
- Demineralized Water
- Plant Indoor Air

Aging Effects Requiring Management

The following demineralized water (make-up) system aging effects require management:

- Loss of material
- Loss of preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the demineralized water (make-up) system component types:

- Flow-Accelerated Corrosion (B2.1.6)
- Bolting Integrity (B2.1.7)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
- One-Time Inspection (B2.1.16)
- Water Chemistry (B2.1.2)
- External Surfaces Monitoring Program (B2.1.20)

3.4.2.1.6 Auxiliary Feedwater System

Materials

The materials of construction for the auxiliary feedwater system component types are:

- Aluminum
- Carbon Steel
- Stainless Steel
- Stainless Steel Cast Austenitic

Environment

The auxiliary feedwater system components are exposed to the following environments:

- Atmosphere/ Weather
- Buried
- Dry Gas
- Encased in Concrete
- Lubricating Oil
- Plant Indoor Air
- Secondary Water
- Steam

Aging Effects Requiring Management

The following auxiliary feedwater system aging effects require management:

- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary feedwater system component types:

- Flow-Accelerated Corrosion (B2.1.6)
- Bolting Integrity (B2.1.7)
- Buried Piping and Tanks Inspection (B2.1.18)
- External Surfaces Monitoring Program (B2.1.20)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
- Lubricating Oil Analysis (B2.1.23)
- One-Time Inspection (B2.1.16)
- Water Chemistry (B2.1.2)

Table 3.3.2-2 Auxiliary Systems – Summary of Aging Management Evaluation – Spent Fuel Pool Cooling and Cleanup System (Continued)

Piping	DF, LBS, PB, SIA	Stainless Steel	Treated Borated Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.A3-10	3.3.1.90	E, 3, 4
Piping	DF, LBS, PB, SIA	Stainless Steel	Treated Borated Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	None	None	H, 3
Pump	LBS, PB, SIA	Stainless Steel	Borated Water Leakage (Ext)	None	None	VII.J-16	3.3.1.99	A

Notes for Table 3.3.2-1:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

1 Loss of preload is conservatively considered to be applicable for all closure bolting.

2 The Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.16) manage loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking. The One-Time Inspection program (B2.1.16) includes selected components at susceptible locations.

3 Wall thinning due to erosion-corrosion is managed by the Flow-Accelerated Corrosion program (B2.1.6).

Table 3.3.2-9 Auxiliary Systems – Summary of Aging Management Evaluation – Chilled Water HVAC System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, PB, SIA	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.F2-18	3.3.1.47	B
Piping	LBS, PB, SIA	Carbon Steel	Closed Cycle Cooling Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	None	None	H,1
Piping	LBS, PB, SIA	Carbon Steel	Demineralized Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.B1-11	3.4.1.04	A
Piping	PB, SIA	Carbon Steel	Dry Gas (Int)	None	None	VII.J-23	3.3.1.97	A
Piping	PB	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VII.C2-13	3.3.1.14	B
Piping	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B

Notes for Table 3.3.2-9:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

F Material not in NUREG-1801 for this component.

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

~~None~~

1 Wall thinning due to erosion-corrosion is managed by the Flow-Accelerated Corrosion program (B2.1.6)

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Demineralized Water (Make-up) System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Closure Bolting	SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	None	None	H, 1
Closure Bolting	SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	Bolting Integrity (B2.1.7)	VIII.H-1	3.4.1.22	B
Closure Bolting	LBS, SIA	Stainless Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	None	None	H, 1
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VIII.G-34	3.4.1.30	B
Piping	SIA	Stainless Steel	Atmosphere/ Weather (Ext)	None	None	None	None	G
Piping	LBS, PB, SIA	Stainless Steel	Demineralized Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.E-29	3.4.1.16	A
Piping	LBS, PB, SIA	Stainless Steel	Demineralized Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	None	None	H,2
Piping	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A

Notes for Table 3.4.2-4:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

~~E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.~~

G Environment not in NUREG-1801 for this component and material.
H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:
1 Loss of preload is conservatively considered to be applicable for all closure bolting.
2 Wall thinning due to erosion-corrosion is managed by the Flow-Accelerated Corrosion program (B2.1.6).

Table 3.4.2-6 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB	Carbon Steel	Secondary Water (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VIII.G-37	3.4.1.01	A
Piping	LBS, PB, SIA	Carbon Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.G-38	3.4.1.04	A
Piping	LBS, PB, SIA	Carbon Steel	Secondary Water (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VIII.E-35	3.4.1.29	B
Piping	LBS, PB, SIA	Stainless Steel	Atmosphere/ Weather (Ext)	None	None	None	None	G
Piping	SIA	Stainless Steel	Atmosphere/ Weather (Int)	None	None	None	None	G, 3
Piping	PB, SIA	Stainless Steel	Buried (Ext)	Loss of material	Buried Piping and Tanks Inspection (B2.1.18)	VIII.G-31	3.4.1.17	E
Piping	SIA	Stainless Steel	Encased in Concrete (Ext)	None	None	VIII.I-11	3.4.1-43	A
Piping	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	None	None	VIII.I-10	3.4.1.41	A
Piping	LBS, PB, SIA	Stainless Steel	Secondary Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VIII.G-32	3.4.1.16	A
Pump	PB	Carbon Steel	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	VIII.G-35	3.4.1.07	B

A1.6 FLOW-ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon or low alloy steel piping and system components which contain high energy fluids (both single phase and two phase). The FAC program also manages wall thinning due to other causes, such as erosion/corrosion.

The objectives of the FAC program are achieved by (a) identifying system components susceptible to FAC, (b) an analysis using a predictive code such as CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance for follow-up inspections, (d) repairing or replacing components, as determined by the guidance provided by the program, and (e) continual evaluation and incorporation of the latest technologies, industry and plant in-house operating experience. Procedures and methods used by the FAC program are consistent with STP commitments to NRC Bulletin 87-01, *Thinning of Pipe Wall in Nuclear Power Plants*, and NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*. The program relies on implementation of the EPRI guidelines of NSAC-202L, *Recommendations for an Effective Flow Accelerated Corrosion Program.*

B2.1.6 Flow Accelerated Corrosion

Program Description

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon or low alloy steel piping and system components which contain high energy fluids (both single phase and two phase). The program also manages wall thinning due to other causes, such as erosion/corrosion. The program implements the EPRI guidelines in NSAC-202L-R3 to detect, measure, monitor, predict and mitigate component wall thinning. To aid in the planning of inspections and choosing inspection locations, STP utilizes the EPRI predictive computer program CHECWORKS that uses the implementation guidance of NSAC-202L-R3.

The objectives of the FAC program at STP are achieved by (a) identifying system components susceptible to FAC, (b) performing analyses using the predictive code CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance for follow-up inspections, (d) repairing, replacing, or performing evaluations for components not acceptable for continued service, based on the wear rates and minimum acceptable design thickness, and (e) evaluating and incorporating the latest technologies, industry and plant in-house operating experience.

Procedures and methods used by the FAC program are consistent with STP commitments to NRC Bulletin 87-01, *Thinning of Pipe Wall in Nuclear Power Plants*, and NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

NUREG-1801 Consistency

The Flow-Accelerated Corrosion program is an existing program that is consistent, with exception, to NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

Exceptions to NUREG-1801

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

NUREG-1801, Section XI.M17 indicates the Flow-Accelerated Corrosion program relies on implementation of EPRI guidelines in NSAC-202L-R2. However, STP uses the recommendations provided in the EPRI Guideline NSAC-202L-R3. The new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations are intended to refine and enhance those of previous revisions without contradictions to ensure continuity of existing plant FAC programs

Enhancements

None

Operating Experience

Review of work orders from 1998 through present showed that there has been no reported FAC-related leak or rupture at STP for the components within the scope of license renewal. Most of the work orders identified the effect of wall thinning during the FAC program inspections. There were cases where the allowable thickness determined in accordance with the program guidelines was reached and more rigorous stress analyses were performed to justify continued service and to postpone the replacement. Problems identified during implementation of the program activities were not significant to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. Industry and plant operating experience have been reviewed for applicability and adjustments have been made to outage inspection lists in accordance with program guidelines.

For refueling outages 1RE12 through 1RE14 (April 2008) and 2RE10 through 2RE12, 102 to 112 locations of large-bore systems were selected for inspection before the outage. The scope was expanded when necessary based on UT findings. An inspection location included the subject component (such as an elbow) and its adjacent area (such as upstream and downstream piping). For small-bore systems, 28 to 54 inspections were selected before the outage for RT inspections. The scope was also expanded when necessary based on RT findings. Scheduling of piping replacements for each outage takes into consideration 1) the projected remaining service life of the pipe based on FAC analysis; 2) industry experience of wall thinning for the pipe and its operating environment; and 3) cost of replacement compared to the cost of performing future inspections. The selections of FAC-resistant materials were stainless steel or chrome-moly alloy. Baseline inspections were performed for selected replacement locations of chrome-moly alloy.

Conclusion

The continued implementation of the Flow-Accelerated Corrosion program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

RAI 3.3.2.13-1	LRA Sections 3.3.2.1.13, 3.3.2.1.15 LRA Tables 3.3.2-13, 3.3.2-15

3.3.2.1.13 Miscellaneous HVAC Systems (In Scope)

Materials

The materials of construction for the miscellaneous HVAC systems (In Scope) component types are:

- Carbon Steel
- Carbon Steel (Galvanized)
- Elastomer

Environment

The miscellaneous HVAC systems (In Scope) component types are exposed to the following environments:

- Encased in Concrete
- Plant Indoor Air
- Ventilation Atmosphere

Aging Effects Requiring Management

The following miscellaneous HVAC systems (In Scope) aging effects require management:

- Hardening and loss of strength
- Loss of material
- <u>Loss of preload</u>

Aging Management Programs

The following aging management programs manage the aging effects for the miscellaneous HVAC systems (In Scope) component types:

- Bolting Integrity (B2.1.7)
- External Surfaces Monitoring Program (B2.1.20)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)

3.3.2.1.15 Standby Diesel Generator Building HVAC System

Materials

The materials of construction for the standby diesel generator building HVAC system component types are:

- Carbon Steel
- Carbon Steel (Galvanized)
- Elastomer
- Stainless Steel

Environment

The standby diesel generator building HVAC system component types are exposed to the following environments:

- Encased in Concrete
- Plant Indoor Air
- Ventilation Atmosphere

Aging Effects Requiring Management

The following standby diesel generator building HVAC system aging effects require management:

- Hardening and loss of strength
- Loss of material
- <u>Loss of preload</u>

Aging Management Programs

The following aging management programs manage the aging effects for the standby diesel generator building HVAC system component types:

- Bolting Integrity (B2.1.7)
- External Surfaces Monitoring Program (B2.1.20)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)

Table 3.3.2-13 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous HVAC Systems (In Scope)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Blower	PB	Carbon Steel	Ventilation Atmosphere (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.F2-3	3.3.1.72	B
Closure Bolting	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.7)	VII.I-4	3.3.1.43	B, 1
Closure Bolting	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	VII.I-5	3.3.1.45	B, 1
Damper	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F2-2	3.3.1.56	B

Table 3.3.2-15 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator Building HVAC System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Blower	PB	Carbon Steel	Ventilation Atmosphere (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.F4-2	3.3.1.72	B
Closure Bolting	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.7)	VII.I-4	3.3.1.43	B, 1
Closure Bolting	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of preload	Bolting Integrity (B2.1.7)	VII.I-5	3.3.1.45	B, 1
Damper	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F4-1	3.3.1.56	B

RAI 3.5.2.11-1	LRA Sections 3.5.2.1.11 LRA Table 3.5.2-11

3.5.2.1.11 Supports

Materials

The materials of construction for the supports component types are:

- Aluminum
- Carbon Steel
- Concrete
- High Strength Low Alloy Steel (Bolting)
- Lubrite
- Stainless Steel

Environment

The supports component types are exposed to the following environments:

- Atmosphere/ Weather (Structural)
- Borated Water Leakage
- Plant Indoor Air (Structural)
- Submerged (Structural)

Aging Effects Requiring Management

The following supports aging effects require management:

- Cracking
- Increase in porosity and permeability, loss of strength
- Loss of material
- Loss of mechanical function
- Loss of preload

Reduction in concrete anchor capacity

Table 3.5.2-11 Containments, Structures, and Component Supports – Summary of Aging Management Evaluation – Supports (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
High Strength Bolting	SS	High Strength Low Alloy Steel (Bolting)	Plant Indoor Air (Structural) (Ext)	Cracking	Bolting Integrity (B2.1.7)	III.B1.1-3	3.5.1.51	B
High Strength Bolting	SS	High Strength Low Alloy Steel (Bolting)	Plant Indoor Air (Structural) (Ext)	Loss of material	Bolting Integrity (B2.1.7)	III.B1.1-4	3.5.1.51	B
High Strength Bolting	SS	High Strength Low Alloy Steel (Bolting)	Plant Indoor Air (Structural) (Ext)	Loss of preload	ASME Section XI, Subsection IWF (B2.1.29)	None	None	H, 2

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.

H Aging effect not in NUREG-1801 for this component, material, and environment combination.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1 NUREG-1801 does not provide a line to evaluate stainless steel components outdoors under the ASME Section XI, Subsection IWF program (B2.1.29).

2 GALL Rev 1 does not identify Loss of Preload as an AERM for structural bolting. This line is consistent with GALL Rev 2, III.B1.1.TP-229.

RAI B2.1.16-3	Appendix B2.1.16.

B2.1.16 One-Time Inspection

Program Description

The One-Time Inspection program manages loss of material, cracking, and reduction of heat transfer. The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (B2.1.2), Fuel Oil Chemistry program (B2.1.14), and Lubricating Oil Analysis program (B2.1.23).

The One-Time Inspection program will be implemented by STP prior to the period of extended operation. Plant system piping and components identified in the one-time inspection procedure will be subject to one-time inspections on a sampling basis, using qualified inspection personnel, following established ASME Code Section V Non-Destructive Examination techniques appropriate to each inspection. The One-Time Inspection program determines non-destructive examination (NDE) sample sizes ~~are~~ based on the ~~number~~ population of components in a group sharing the same material, environment, and aging effects. For each population, a representative sample size of 20 percent of the population is selected up to a maximum of 25 components. The components making up the sample are those determined to be most susceptible to degradation based on a review of environment, ~~condition~~ conditions and operating experience. The program will focus on bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. Inspections will be performed using a variety of NDE methods, including visual, volumetric, and surface techniques by ~~other activities may~~ qualified inspectors. The program will not be used ~~if they satisfy~~ for component inspections with known age-related degradation mechanisms, or when the ~~requirements of~~ environment in the ~~OTI program~~ period of extended operation is not equivalent to that in the prior 40 years. The One-Time Inspection program specifies corrective actions ~~and increased sampling of piping/components~~ if aging effects are found ~~during~~. The corrective action program may specify follow-up inspections for confirmation of aging effects at the same or different locations. If aging effects are detected, a plant-specific program will be developed for the material~~/~~, environment, and aging effect combination ~~inspections.~~ that has produced the aging effects.

The one-time inspections will be performed no earlier than 10 years prior to the period of extended operation. All one-time inspections will be completed prior to the period of extended operation. Completion of the One-Time Inspection program in this time period will assure that potential aging effects will be manifested based on at least 30 years of STP operation. Major elements of the STP One-Time Inspection program will include:

a) Identifying piping and component populations subject to one-time inspections based on common materials and environments,

b) Determining the sample size of components to inspect for each material-environment group,

c) Selecting piping and components within the material-environment groups for inspection based on criteria provided in the one-time inspection procedure,

d) Conducting one-time inspections of the selected components within the sample using ASME Code Section V Non-Destructive Examination techniques and acceptance criteria consistent with the design codes/standards or ASME Section XI as applicable to the component,

e) Evaluating inspection results and initiating corrective action for any aging effects found.

NUREG-1801 Consistency

The One-Time Inspection program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.M32, One-Time Inspection.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

During the 10 year period prior to the period of extended operation, one-time inspections will be accomplished at STP using ASME Code Section V Non-Destructive Examination techniques to identify possible aging effects. ASME code techniques in the ASME Section XI ISI Program have proven to be effective in detecting aging effects prior to loss of intended function. Review of STP plant-specific operating experience associated with the ISI Program has not revealed any ISI Program adequacy issues with the STP ASME Section XI ISI Program. The same Non-Destructive Examination techniques used in the ASME Section XI ISI Program will be used in the One-Time Inspection program. Using ASME Code Section V Non-Destructive Examination techniques will be effective in identifying aging effects, if present.

As additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into the program through the STP condition reporting and operating experience programs.

Conclusion

The implementation of the One-Time Inspection program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

RAI 4.3-2	LRA Table 4.3-2
RAI 4.3-13	LRA Table 4.3-2

Table 4.3-2 STP Units 1 and 2 Transient Cycle Count 60-year Projections

Transient Description	UFSAR Design Cycles	Program Limiting Value	Baseline Events Up to Year End 2008		Projected Events for 60-Years	
			Unit 1 (1988-2008)	Unit 2 (1989-2008)	Unit 1	Unit 2
Normal Conditions						
1. RCS Heatup at 100°F/hr	200	200	44	28	86	78
2. RCS Cooldown at 100°F/hr	200	200	43	27	85	76
3. Pressurizer Heatup at 100°F/hr	NS	200	44	28	86	78
4. Pressurizer Cooldown at 200°F/hr	200	200	43	27	85	76
5. Unit Loading at 5% of Full Power/min	U1-3,000 U2-10,300	3,000	NP(1)	NP	NP	NP
6. Unit Unloading at 5% of Full Power/min	U1-3,000 U2-10,300	3,000	NP(1)	NP	NP	NP
7. Step Load Increase of 10% of Full Power	2,000	~~2,000~~1,200(2)	16	10	29	18
8. Step Load Decrease of 10% of Full Power	2,000	~~2,000~~1,200(2)	19	12	37	24
9. Large Step Load Decrease with Steam Dump	200	~~200~~120(2)	13	13	25	26
10. Steady State Fluctuations, Initial	1.5×10^5	~~1.5×10^5~~ 9×10^4 (2)	NP(3)	NP	NP	NP
11. Steady State Fluctuations, Random	3.0×10^6	~~3.0×10^6~~ 1.8×10^6 (2)	NP(3)	NP	NP	NP
12. Feedwater Cycle at Hot Shutdown	2,000	--	--	--	--	--
Steam Generator A	--	~~2,000~~1,200(2)	54	72	259	488
Steam Generator B	--	~~2,000~~1,200(2)	47	71	227	480
Steam Generator C	--	~~2,000~~1,200(2)	50	70	239	474
Steam Generator D	--	~~2,000~~1,200(2)	50	102	239	691
13. Loop Out of Service, Normal (Active) Loop Shutdown	80	80	0	0	1	1
14. Loop Out of Service, Normal (Inactive) Loop Startup	70	70	NP(4)	NP	NP	NP
15. Unit Loading Between 0-15% of Full Power	500	500	NP(5)	NP	NP	NP

Table 4.3-2 STP Units 1 and 2 Transient Cycle Count 60-year Projections

Transient Description	UFSAR Design Cycles	Program Limiting Value	Baseline Events Up to Year End 2008		Projected Events for 60-Years	
			Unit 1 (1988-2008)	Unit 2 (1989-2008)	Unit 1	Unit 2
16. Unit Unloading Between 0-15% of Full Power	500	500	NP[5]	NP	NP	NP
17. Boron Concentration Equalization	26,400	~~26,400~~15,840[2]	NP[6]	NP	NP	NP
18. Refueling	80	80	15	13	42	41
19. Primary Side Leak Test	U1-120 U2-200	~~U1-~~120 ~~U2-200~~	1	0	1	1
20. Secondary Side Leak Test	80	--	--	--	--	--
Steam Generator A	--	80	0	0	1	1
Steam Generator B	--	80	0	0	1	1
Steam Generator C	--	80	0	0	1	1
Steam Generator D	--	80	0	0	1	1
21. Tube Leak Test	800	Type I: 400 Type II: 200 Type III: 120 Type IV: 80	0	0	1	1
22. Turbine Roll Test	20	20	9	5	9	5
23. Charging Flow 50% Step Increase and Return	NS	~~24,000~~14,400	7	0	140	200
Upset Conditions						
24. Loss of Load (Without Immediate Reactor Trip)	80	~~80~~48[2]	6	2	12	3
25. Loss of Power (Blackout; Loss of Offsite AC Power with Natural Circulation in the RCS)	40	40	4	4	6	6
26. Partial Loss of RCS Flow (Loss of One RCP)	80	~~80~~48[2]	5	4	9	11
27. Reactor Trip from Full Power, without Cooldown.	230	~~230~~138[2]	29	23	45	56
28. Reactor Trip from Full Power, with Cooldown, without Safety Injection	160	~~160~~96[2]	13	11	19	26

Table 4.3-2 STP Units 1 and 2 Transient Cycle Count 60-year Projections

Transient Description	UFSAR Design Cycles	Program Limiting Value	Baseline Events Up to Year End 2008		Projected Events for 60-Years	
			Unit 1 (1988-2008)	Unit 2 (1989-2008)	Unit 1	Unit 2
29. Reactor Trip from Full Power, with Cooldown, with Safety Injection	10	10	1	1	3	3
30. Inadvertent RCS Depressurization	20	20	0	0	1	1
31. Inadvertent RCS Depressurization due to Inadvertent Auxiliary Spray	10	10	0	0	1	1
32. Inadvertent Startup of an Inactive RCS Loop	10	~~10~~6[2]	0[7]	0	1	1
33. Control Rod Drop	80	~~80~~48[2]	1	3	3	8
34. Inadvertent ECCS Actuation (No Safety Injection)	60	60	4	3	6	8
35. Operating Basis Earthquake (OBE)[i]	5	5	0	0	1	1
36. Excessive Feedwater Flow	30	30	3	2	7	6
37. Actuation of RCS Cold Over-pressurization Mitigation System (COMS)	10	10	3	1	4	2
38. Normal Charging Letdown Shutoff and Letdown Trip	NS	~~60~~36	7	18	16	54
39. Letdown Trip with Prompt Return to Service	NS	~~200~~120	3	3	10	10
40. Letdown Trip with Delayed Return to Service	NS	~~20~~12	3	0	9	1
41. Charging Trip with Prompt Return to Service	NS	~~20~~12	10	0	15	1
42. Charging Trip With Delayed Return to Service	NS	~~20~~12	0	0	1	1
Test Conditions						
43. Primary Side Hydrostatic Test	10	1	1	1	1	1
44. Secondary Side Hydrostatic Test (each generator)	10	10	1	1	1	1

Table 4.3-2 STP Units 1 and 2 Transient Cycle Count 60-year Projections

Transient Description	UFSAR Design Cycles	Program Limiting Value	Baseline Events Up to Year End 2008		Projected Events for 60-Years	
			Unit 1 (1988-2008)	Unit 2 (1989-2008)	Unit 1	Unit 2
Auxiliary Conditions - Accumulator Safety Injections						
45. Inadvertent RCS Depressurization with HHSI	NS	20	0	0	1	1
46. Inadvertent Accumulator Blowdown	NS	4	0	0	1	1
47. RHR Operation	NS	200	44	27	89	76
48. High Head Safety Injection	NS	~~54~~30	1	0	3	1

1 Transients 5 and 6 "Unit Loading and Unloading at 5% of Full Power/min" are listed in UFSAR Table 3.9-8, however they are not projected and are marked as "NP." STP does not practice load following.

2 The program limiting value is based on the fatigue analyses for the alternate and normal charging lines. The analyses reduced the FSAR design cycles by 60% based on rotating between the normal and alternate charging paths, so each path would experience 50% of the transients. An additional 10% was added for each path as a conservatism to account for uncertainty in the availability of each path.

~~2~~3 Transients 10 and 11 "Steady State Fluctuations" are listed in UFSAR Table 3.9-8; however they are not projected and are marked as "NP." These transients do not have a significant effect on fatigue and are bounded by transients which are tracked.

~~3~~4 Transient 14 "Loop Out of Service, Normal (Inactive) Loop Startup" is listed in UFSAR Table 3.9-8; however it is not projected and is marked as "NP" because STP normal operation with one inactive loop and the reactor critical is not permitted due to the effect on the UFSAR Chapter 15 safety analysis. The 1 projected cycle of Transient 13, "Loop Out of Service, Normal (Active) Loop Shutdown" has 1 respective startup projection of Transient 32 "Inadvertent Startup of an Inactive RCS Loop."

~~4~~5 Transients 15 and 16 "Unit Loading and Unloading Between 0-15% of Full Power" are listed in UFSAR Table 3.9-8; however they are not projected and are marked as "NP." STP does not practice load following.

~~5~~6 Transient 17 "Boron Concentration Equalization" is listed in UFSAR Table 3.9-8; however it is not projected and marked as "NP." The design cycles are consistent with load follow operation. STP does not load follow and will not approach this limit.~~This transient is bounded by load change transients which are tracked.~~

~~6~~7 Transient 32 "Inadvertent Startup of an Inactive RCS Loop" is projected to 1 cycle as the respective startup to the 1 projected cycles of Transient 13, "Loop Out of Service, Normal (Active) Loop Shutdown."

~~7~~8 Earthquakes include 10 cycles for each event, UFSAR Section 3.7.3.B.2 (OBE) and 3.9.1.1.7.9 (SSE).

RAI 4.3-4	LRA Section 4.3.6 Appendix A3.2.5

4.3.6 ASME Section III Fatigue Analysis of Metal Bellows and Expansion Joints

Summary Description

NUREG-1800, *The Standard Review Plan for License Renewal*, discusses fatigue analysis review requirements for metal bellows. A search of the STP CLB discovered design requirements of the fuel transfer tube penetration bellows, essential cooling water (ECW) and diesel generator cooling water bellows.

The fuel transfer tube penetration bellows TLAA is discussed in Section 4.6.2 of this chapter.

Analysis

STP UFSAR Section 9.5.5, *Diesel Generator Cooling Water System* identifies the design of the diesel generator cooling water and essential cooling water bellows as ASME Section III, Class 3. The STP metal expansion joints design specification requires that these expansion joints be designed in accordance with Section ND of the ASME Section III 1977 Code, including Summer 1977 addenda; and have a minimum design life of 40 years.

The fatigue analyses for the metal expansion joints verify the 40 year design requirement for the diesel generator cooling water and ECW expansion joints by satisfying ASME Section III, Subsection ND-3649.4(d), which limits the component's lifetime cyclical loading.

Disposition: Validation, 10 CFR 54.21(c)(1)(i) and Aging Management, 10 CFR 54.21(c)(1)(iii)

Validation, 10 CFR 54.21(c)(1)(i)

The analyzed numbers of cycles for all but seven of the diesel generator cooling water and ECW expansion joints are greater than the specified numbers of cycles extrapolated to 60 years. Therefore the analyses are valid for these bellows through the period of extended operation. These diesel generator cooling water and ECW expansion joint TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Aging Management, 10 CFR 54.21(c)(1)(iii)

STP has committed to replace, prior to the period of extended operation, the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation. The analyses for the replacement expansion joints will include the period of extended operation. Therefore these seven diesel generator cooling water expansion joint TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.2.5 ASME Section III Fatigue Analysis of Metal Bellows and Expansion Joints

The STP diesel generator cooling water and essential cooling water (ECW) metal expansion joints were designed in accordance with Section ND of the ASME Section III 1977 Code, including Summer 1977 addenda; and have a minimum design life of 40 years. The fatigue analyses for the metal expansion joints verify the 40 year design requirement for the diesel generator cooling water and ECW expansion joints by satisfying ASME Section III, Subsection ND-3649.4(d), which limits the component's lifetime cyclical loading.

The analyzed numbers of cycles for all but seven of the diesel generator cooling water and ECW expansion joints are greater than the specified numbers of cycles extrapolated to 60 years. Therefore, the analyses are valid for these bellows through the period of extended operation. These diesel generator cooling water expansion joint TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

STP has committed to replace, prior to the period of extended operation, the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation. The analyses for the replacement expansion joints will include the period of extended operation. Therefore, these seven diesel generator cooling water expansion joint TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 4.3-6	LRA Table 4.3-8

Table 4.3-8 Summary of Fatigue Usage Factors at NUREG/CR-6260 Sample Locations Adapted to STP Units 1 and 2

Location	Material	40-Year CUF	F_{en}	40-Year EAF CUF	60-Year EAF CUF[(2)]
1. RPV Wall Transition[(1)]	Low Alloy Steel	0.0062	2.455	0.015	0.0225
2. RPV Inlet Nozzle	Low Alloy Steel	0.0342	2.455	0.084	0.126
3. RPV Outlet Nozzle	Low Alloy Steel	0.0167	2.455	0.041	0.0615
4. Hot Leg Surge Nozzle (Safe End)	Stainless Steel	0.8196	9.26	-~~7.5904~~	7.5904~~11.3856~~
5. Charging System Nozzle (Normal Line)	Stainless Steel	0.19814	7.866	-~~1.5585~~	1.5585~~2.3378~~
6. Charging System Nozzle (Alternate Line)	Stainless Steel	0.19814	7.866	-~~1.5585~~	1.5585~~2.3378~~
7. Accumulator Safety Injection Nozzle (Loop 1)	Stainless Steel	0.0769	7.21	0.553	0.830
8. Accumulator Safety Injection Nozzle (Loop 2)	Stainless Steel	0.0769	7.21	0.553	0.830
9. Accumulator Safety Injection Nozzle (Loop 3)	Stainless Steel	0.0769	7.21	0.553	0.830
10. RHR Inlet Nozzle	Stainless Steel	0.0042	15.35	0.064	0.096

1 60-Year EAF CUF is equal to the Design EAF CUF multiplied by 1.5.

2 The RPV Wall Transition location has a larger design CUF than the RPV Bottom Head-to-Shell Juncture location designated in NUREG/CR-6260. Therefore, the RPV Wall Transition location is monitored as the bounding location.

RAI 4.3-9	LRA Section 4.3.3 LRA Appendix A3.2.2

4.3.3 ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals

Summary Description

The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDMs, direct coolant flow past the fuel elements, direct coolant flow to the RPV head, provide gamma and neutron shielding, and guide the incore instrumentation.

The STP reactor vessel internals were designed to meet the intent of the 1974 Edition of Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG, paragraph NG-3311(c); that is, design and construction of core support structures meet Subsection NG in full, and other internals are designed and constructed to ensure that their effects on the core support structures remain within the core support structure limits.

Analysis

Flow-Induced Vibration in the Reactor Vessel Internals (Not a TLAA)

Protection from flow induced vibration is ensured via testing. The STP UFSAR Section 3.9.2.3 discusses the dynamic response analysis of reactor internals under operational flow transients and steady-state conditions.

The Indian Point No. 2 plant was the prototype for a four-loop plant internals verification program and was fully instrumented and tested during hot functional testing. In addition, the Trojan plant and Sequoyah No. 1 plant provided prototype data applicable to STP Units 1 and 2. STP Units 1 and 2 are similar to Indian Point No. 2; the only significant differences are the modifications resulting from (1) the replacement of the annular thermal shield with neutron shielding pads, (2) the change to the UHI-style inverted top hat support structure configurations, and (3) the use of 17 x 17 extended length fuel. These differences were addressed and a detailed review of the STP reactor pressure vessel internals load combinations, allowable stress limits, and other design criteria for vibration effects was not performed because of the plant's similarity to other Westinghouse plants that were found acceptable.

The licensing basis does not describe any time-limited effects for a licensed operating period associated with flow-induced vibration. Therefore there are no TLAAs, in accordance with 10 CFR 54.3(a), Criteria 2 and 3.

Fatigue Analyses Including Effects of Power Uprate and Steam Generator Replacement

Westinghouse evaluated the Unit 1 and 2 reactor vessel internals for the effect of the 1.4% uprating, replacement steam generators, the conversion to $_{Tcold}$ upper head operating conditions with robust fuel assemblies, and tube support pin replacement. The flow-induced vibration stress levels were calculated and are shown to be well below the material high-cycle fatigue endurance limit. Assessment of core support structures limiting margins of safety and fatigue usage factors resulted in meeting ASME Code allowable values as shown in Table 4.3-7.

Table 4.3-7 Reactor Vessel Internals CUF Results

Component	Limiting 40-Year CUF	
	Unit 1	**Unit 2**
Lower Core Support Plate	0.00	0.00
Baffle, Former Assembly	<1 (test)	<1 (test)
Core Barrel Assembly	0.389	0.389
Radial Keys and Clevis Inserts	0.11	0.11
Upper Support Assembly	0.175	0.175
Upper Core Plate	0.80	0.80
Upper Support Column	0.41	0.41
Instrumentation Port Column Assemblies	0.064	0.064

Disposition: Aging Management, 10 CFR 54.21(c)(1)(iii)

The Subsection NG fatigue usage factors for reactor vessel internals do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of normal~~,~~ and upset~~, and emergency~~ transient events. Therefore the increase in operating life to 60 years will not have an effect on these fatigue usage factors so long as the number of transient cycles remains within the 40-year numbers of cycles assumed by the analysis.

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 4.3.1 and B3.1 ensures that the numbers of transients remain below the number actually experienced during the period of extended operation remain below the assumed number; or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The effects of fatigue in the reactor vessel internals will therefore be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii)

A3.2.2 ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals

The STP reactor vessel internals were designed to meet the intent of the 1974 Edition of Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG, paragraph NG-3311(c); that is, design and construction of core support structures meet

Subsection NG in full, and other internals are designed and constructed to ensure that their effects on the core support structures remain within the core support structure limits.

The Subsection NG fatigue usage factors for reactor vessel internals do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of normal~~,~~ and upset~~, and emergency~~ transient events. Therefore, the increase in operating life to 60 years will not have an effect on these fatigue usage factors so long as the number of transient cycles remains within the 40-year numbers of cycles assumed by the analysis.

The Metal Fatigue of Reactor Coolant Pressure Boundary program, described in Section A2.1, ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number; or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The effects of fatigue will therefore be managed for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 4.3-13	LRA Table 4.3-2 (See RAI 4.3-2 for changes to this Table)

RAI 4.3-18	LRA Tables 3.4.2-1, 3.4.2-2, 3.4.2-5, 3.4.2-6, 3.3.2-8 ,3.3.2-19, 3.3.2-20, 3.3.2-21, 3.3.2-22
RAI 3.3.2.3.10-1	LRA Table 3.3.2-20
RAI 3.0-1	LRA Tables 3.3.2-19, 3.3.2-20, 3.3.2-21
RAI 3.3.2.4-1	LRA Tables 3.3.2-19, 3.3.2-20
RAI 4.1-4	LRA Table 3.4.2-1

(See RAI 3.3.2.3.22-1 for changes to LRA Table 3.3.2-22)

Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Main Steam System Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-18	3.3.1.02	A

Table 3.4.2-2 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Steam System and Boilers

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB	Carbon Steel	Steam (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VIII.B1-10	3.4.1.01	A

Table 3.4.2-5 Steam and Power Conversion System – Summary of Aging Management Evaluation – Steam Generator Blowdown System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-18	3.3.1.02	A
Piping	PB	Carbon Steel	Secondary Water (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VIII.D1-7	3.4.1.01	A

Table 3.4.2-6 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-18	3.3.1.02	A

Table 3.3.2-8 Auxiliary Systems – Summary of Aging Management Evaluation – Primary Process Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB	Stainless Steel	Treated Borated Water (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-16	3.3.1.02	A

Table 3.3.2-19 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (CVCS Seal Water Return)	PB	Stainless Steel	Treated Borated Water (Ext)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-17	3.3.1.91	E, 2
Heat Exchanger (CVCS Seal Water Return)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Cracking	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-5	3.3.1.08	E, 2
Heat Exchanger (CVCS Seal Water Return)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Reduction of heat transfer	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	None	None	H, 3
Heat Exchanger (CVCS Seal Water Return)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Loss of material	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)	VII.E1-17	3.3.1.91	E, 2

Table 3.3.2-19 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Lube Oil Cooler)	PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	C
~~Insulation~~	~~INS~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	~~C~~
Insulation	INS	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.2.1.50	C
Insulation	INS	Insulation Calcium Silicate	Plant Indoor Air (Ext)	None	None	None	None	J

Table 3.3.2-19 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Carbon Steel	Steam (Int)	Wall thinning	Flow-Accelerated Corrosion (B2.1.6)	VII.A-17	3.4.1-29	B
Piping	LBS	Carbon Steel	Steam (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended	VIII.B1-10	3.4.1.01	A
Piping	LBS	Copper Alloy	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection	VII.E1-12	3.3.1.26	B

Notes for Table 3.3.2-19:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.

F Material not in NUREG-1801 for this component.

G Environment not in NUREG-1801 for this component and material.

H Aging effect not in NUREG-1801 for this component, material, and environment combination.

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1 NUREG-1801 does not address the aging effect of nickel-alloys in borated water leakage. Nickel-alloys subject to an air with borated water leakage environment are similar to stainless steel in a borated water leakage environment and do not experience aging effects due to borated water leakage.

2 The Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.16) manage loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking. The One-Time Inspection program (B2.1.16) includes selected components at susceptible locations.

3 The reduction of heat transfer aging effect is not identified in NUREG-1801 for this component, material, and environment combination. Reduction of heat transfer is not expected in heat exchangers with reactor coolant or treated borated water environments as long as water chemistry is maintained. Reduction of heat transfer is managed with Water Chemistry (B2.1.2) and One Time Inspection (B2.1.16).

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Accumulator	PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	C
Blower	HT, PB	Cast Iron	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.H2-23	3.3.1.47	D
Blower	HT, PB	Cast Iron (Gray Cast Iron)	Closed Cycle Cooling Water (Int)	Reduction of heat transfer	Closed-Cycle Cooling Water System (B2.1.10)	None	None	H, 2
Blower	PB	Cast Iron	Diesel Exhaust (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.H2-2	3.3.1.18	E

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Filter	FIL, PB	Aluminum	Lubricating Oil (Int)	Loss of material	Lubricating Oil Analysis (B2.1.23) and One-Time Inspection (B2.1.16)	None	None	G
~~Filter~~	~~FIL, PB~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	A
Filter	FIL,PB	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.2.1.50	A
Filter	SIA	Carbon Steel	Dry Gas (Int)	None	None	VII.J-23	3.3.1.97	A

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (DG Jacket Water)	PB	Carbon Steel	Raw Water (Int)	Loss of material	Open Cycle Cooling Water System (B2.1.9)	VII.H2-22	3.3.1.76	B
~~Heat Exchanger (DG Jacket Water)~~	~~HT, PB~~	~~Titanium~~	~~Closed Cycle Cooling Water (Ext)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~F~~
Heat Exchanger (DG Jacket Water)	HT, PB	Titanium	Closed Cycle Cooling Water (Ext)	Reduction of heat transfer	Closed-Cycle Cooling Water System (B2.1.10)	None	None	F
Heat Exchanger (DG Jacket Water)	HT, PB	Titanium	Raw Water (Int)	Reduction of heat transfer	Open Cycle Cooling Water System (B2.1.9)	None	None	F

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (DG Lube Oil)	HT, PB	Titanium	Raw Water (Int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.9)	None	None	F
~~Heat Exchanger (DG Turbo Air Intercooler)~~	~~HT~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	A
Heat Exchanger (DG Turbo Air Intercooler)	HT	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.2.1.50	A

Heat Exchanger (DG Turbo Air Intercooler)	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.H2-3	3.3.1.59	B

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (DG Turbo Air Intercooler)	PB	Carbon Steel	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.H2-21	3.3.1.71	B
~~Heat Exchanger (DG Turbo Air Intercooler)~~	~~HT, PB~~	~~Titanium~~	~~Closed Cycle Cooling Water (Int)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~F~~
Heat Exchanger (DG Turbo Air Intercooler)	HT, PB	Titanium	Closed Cycle Cooling Water (Int)	Reduction of heat transfer	Closed-Cycle Cooling Water System (B2.1.10)	None	None	F
Heat Exchanger (DG Turbo Air Intercooler)	HT, PB	Titanium	Plant Indoor Air (Ext)	None	None	None	None	F

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.H2-23	3.3.1.47	B

Piping	PB	Carbon Steel	Diesel Exhaust (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended	VII.E1-18	3.3.1.02	A
Piping	PB	Carbon Steel	Diesel Exhaust (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.H2-2	3.3.1.18	E

Table 3.3.2-20 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator and Auxiliaries (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS, PB, SIA	Copper Alloy	Plant Indoor Air (Ext)	None	None	VIII.I-2	3.4.1.41	A
~~Valve~~	~~LBS, SIA~~	~~Copper Alloy~~	~~Plant Indoor Air (Int)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~G~~
Valve	LBS, SIA	Copper Alloy	Plant Indoor Air (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components(B2.1.22)	VII.G-9	3.3.1.28	E
Valve	LBS, PB, SIA	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed-Cycle Cooling Water System (B2.1.10)	VII.C2-10	3.3.1.50	B

Notes for Table 3.3.2-20:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F Material not in NUREG-1801 for this component
G Environment not in NUREG-1801 for this component and material.
H Aging effect not in NUREG-1801 for this component, material, and environment combination.

Plant Specific Notes:
1 Loss of preload is conservatively considered to be applicable for all closure bolting.
2 Reduction in heat transfer due to fouling is a potential aging effect/mechanism for cast iron (gray cast iron) turbocharger components in closed cycle cooling water.

Table 3.3.2-21 Auxiliary Systems – Summary of Aging Management Evaluation – Nonsafety-related Diesel Generators and Auxiliary Fuel Oil System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flame Arrestor	PB	Aluminum	Fuel Oil (Int)	Loss of material	Fuel Oil Chemistry (B2.1.14) and One-Time Inspection (B2.1.16)	VII.H1-1	3.3.1.32	B
~~Flame Arrestor~~	~~PB~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	A
Flame Arrestor	PB	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.3.1.50	A
Flame Arrestor	PB	Carbon Steel	Fuel Oil (Int)	Loss of material	Fuel Oil Chemistry (B2.1.14) and One-Time Inspection (B2.1.16)	VII.H1-10	3.3.1.20	D

Table 3.3.2-21 Auxiliary Systems – Summary of Aging Management Evaluation – Nonsafety-related Diesel Generators and Auxiliary Fuel Oil System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.H1-8	3.3.1.60	B
Piping	PB	Carbon Steel	Diesel Exhaust (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	VII.E1-18	3.3.1.02	A

Piping	PB	Carbon Steel	Diesel Exhaust	Loss of material	Inspection of Internal Surfaes in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.H2-2	3.3.1.18	E

RAI 4.3-20	LRA Section 4.3.2.10 LRA Appendix A3.2.1.10

4.3.2.10 High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

Summary Description

Branch Technical Position (BTP) MEB 3-1 provides guidance for determining the types and locations of postulated high-energy line breaks outside containment, and has historically been used for the same purpose inside containment. BTP MEB 3-1 guidance for ASME III Class 1 piping requires postulating breaks at intermediate locations where the design basis usage factor equals or exceeds 0.1.

UFSAR Section 3.6.1 states that selection of pipe failure locations and evaluation of the consequences on nearby essential systems, components, and structures are presented and are in accordance with the requirements of 10 CFR 50, Appendix A, GDC 4. Selections and evaluations are in accordance with the guidance of NRC BTP MEB 3-1.

Analysis

With the exception of the reactor coolant system primary loops, to which a leak-before-break (LBB) analysis applies, breaks in piping with ASME Section III Class 1 fatigue analyses are identified based on a limiting stress criterion; and on a cumulative usage factor criterion. The postulation of break locations based on the fatigue criterion is a TLAA. No additional break locations will result from license renewal as long as the current design basis cumulative usage factor analyses remain valid.

Increased CUF for Break Consideration

Westinghouse justified elimination of break locations in the accumulator safety injection lines and the pressurizer surge line based on increasing the CUF for break consideration from 0.1 to 0.4. Vibration testing was performed to confirm that the level of alternating stress was well below the level required to produce crack growth. STP also provided the results of fatigue crack growth analyses for the pressurizer surge line. These fatigue crack growth analyses established that flaws would not reach the flaw depths allowed in paragraph IWB-3640 of the ASME code during the plant life.

In the matter of increasing the minimum acceptable value of CUF to 0.4, the NRC staff concluded that a generic use of 0.4 is unacceptable. In a letter dated December 31, 1986, the staff informed STP that 40 specific breaks in the pressurizer surge line and the safety injection lines need not be postulated although the CUF values exceeded 0.1.

The analyses that evaluated fatigue crack growth and cumulative usage factor in the pressurizer surge line, and the accumulator safety injection line depend on the standard number of cycles for a 40 year reactor lifetime. Therefore these analyses are TLAAs.

In response to NRC Regulatory Issue Summary (RIS) 2010-07 Westinghouse performed a plant specific evaluation of STP Units 1 and 2 pressurizer surge line analyses for the effects of PWSCC. The evaluation determined that the original analysis conclusions remain valid and the pressurizer surge line pipe breaks should not be considered in the structural basis of STP Units 1 and 2 after weld overlay application.

Elimination of Arbitrary Intermediate Breaks in Class 2 and 3 Piping

The NRC also approved the elimination of arbitrary intermediate breaks. Elimination of the arbitrary intermediate breaks required a commitment by STP to consider fatigue effects in considered fatigue effects for welded attachments to Class 2 and 3 piping in accordance with paragraph NC/ND-3645 of the ASME code. Detailed stress and fatigue analyses were performed for five integral pipe supports that were determined to be bounding.

The analyses which calculated usage factors are based on the standard set of 40-year cycles; therefore, these analyses are TLAAs.

When the usage factors are multiplied by 1.5 to extend the analyzed life to 60 years, two of the five integral welded attachments will possibly experience CUFs greater than 1.0 during the period of extended operation. These are the pipe supports in the main feedwater system, and in the charging system. The remaining three supports are validated for license renewal because their 60 year CUF values show a large margin from 1.0.

The main feedwater piping support fatigue will be managed by cycle counting. The fatigue usage of the charging nozzle will bound the fatigue usage of the integral attachments. Therefore the monitoring of the charging nozzle is sufficient to assure that the charging system piping support will not exceed the Code allowable value.

Break Exclusion Zones

STP has containment penetration break exclusion regions ("no break zones") for the Main Steam and Feedwater systems, in the containment penetration piping between the penetration and containment isolation valves. These zones contain no ASME Section III Class 1 piping with fatigue analyses. Therefore their qualification is based only on calculated stress, and the break locations in these "no break zones" are independent of time and are not supported by a TLAA by 10 CFR 54.3(a), Criterion 3.

Disposition: Projection, 10 CFR 54.21(c)(1)(ii); and Aging Management, 10 CFR 54.21(c)(1)(iii)

Projection of Fatigue of Other Welded Attachments to Class 2 and 3 Lines

Other than those for the charging system and the main feedwater system, the fatigue analyses for the welded attachments to Class 2 and 3 piping which support the elimination of arbitrary intermediate break locations demonstrate a CUF less than 1.0 during the period of extended operation. Therefore these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

Aging Management of Class 1 Break Locations and Welded Attachments to Charging and Main Feedwater Lines

Break locations which depend on usage factor, and the fatigue crack growth analyses which support the increase in the CUF for break considerations in the pressurizer surge and accumulator lines will remain valid as long as the numbers of cycles assumed by the analysis are not exceeded. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 4.3.1 and B3.1 ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number; or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The program also ensures that the charging line weld attachments CUF will be below the Code allowable. The effects of fatigue will therefore be managed for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.2.1.10 High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

With the exception of the reactor coolant system primary loops, to which a leak-before-break (LBB) analysis applies, breaks in piping with ASME Section III Class 1 fatigue analyses are identified based on a limiting stress criterion; and on a cumulative usage factor criterion. No additional break locations will result from license renewal as long as the current design basis cumulative usage factor analyses remain valid.

Westinghouse justified elimination of break locations in the accumulator safety injection lines and the pressurizer surge line based on increasing the CUF for break consideration from 0.1 to 0.4.

In response to NRC Regulatory Issue Summary (RIS) 2010-07 Westinghouse performed a plant specific evaluation of STP Units 1 and 2 pressurizer surge line analyses for the effects of PWSCC. The evaluation determined that the original analysis conclusions remain valid and the pressurizer surge line pipe breaks should not be considered in the structural basis of STP Units 1 and 2 after weld overlay application.

The NRC also approved the elimination of arbitrary intermediate breaks requiring a commitment by STP to consider fatigue effects in welded integral attachments to Class 2 and 3 piping. STP performed an analysis in accordance with paragraph NC/ND-3645 of the ASME code for five integral pipe supports that were determined to be bounding.

The Class 1 break locations, the fatigue crack growth analyses, which support the increase in the CUF for break considerations in the pressurizer surge and accumulator lines, and welded attachments to charging and the main feedwater systems which depend on usage factor will remain valid as long as the numbers of cycles assumed by the analysis are not exceeded. The Metal Fatigue of Reactor Coolant Pressure Boundary program, described in Section A2.1, ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number; or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The program also ensures that the charging line weld attachments CUF will be below the Code allowable. The effects of fatigue will therefore be managed for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Other than those for the charging system and the main feedwater system, the fatigue analyses for the welded attachments to Class 2 and 3 piping which support the elimination of arbitrary intermediate break locations demonstrate a CUF less than 1.0 during the period of extended operation. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

RAI 4.3-22	LRA Section 4.3.2.6 LRA Appendix A3.2.1.6

4.3.2.6 ASME III Class 1 Valves

Summary Description

STP Class 1 valves are designed to ASME III, Subsection NB, 1974 Edition with Summer 1975 addenda (pressurizer safety and control valves) or the 1974 Edition with Winter 1975 addendum (motor-operated, manual valves 3" and larger, and all valves 2" and smaller). ASME Section III requires a fatigue analysis only for Class 1 valves with an inlet piping connection greater than four inches nominal pipe size.

Analysis

Code Fatigue Analyses

Fatigue analyses or evaluations were performed for the valves listed in Table 4.3-6:

Table 4.3-6 Summary of STP Class 1 Valve Fatigue Analyses

Valve, Specification, and Analysis Descriptions	Calculated Ops N_A for NB-3545.3 Normal Duty(1)	Maximum CUF I_t for NB-3550 Cyclic Loads(1)
6" Pressurizer Safety Relief Valves	>2,000	I_{t40} = 0.0276 I_{t60} = 0.04 14
12" RHR Pump Suction Isolation Valves	>2,000	I_{t40} = 0.64 I_{t60} = 0.96
6" Hi Head Safety Injection Pump Discharge Check Valves	>2,000	I_{t40} = 0.15 I_{t60} = 0.225
8" Hi Head Safety Injection Pump Discharge Check Valves	>2,000	I_{t40} = 0.14 I_{t60} = 0.21
8" Lo Head Safety Injection To Hot Leg Check Valves	>2,000	I_{t40} = 0.14 I_{t60} = 0.21
12" Safety Injection To Cold Leg Injection Check Valves and Safety Injection Accumulator Outlet Valves	>2,000	I_{t40} = 0.05 I_{t60} = 0.075
8" Lo Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve	>2,000	I_{t40} = 0.14 I_{t60} = 0.21
2" CVCS Auxiliary Spray Check Valves	>2,000	I_{t40} = 0.2063 I_{t60} = 0.3095
2" RCP Seal Injection First Check Valves and RCP Seal Injection Second Check Valves	>2,000	I_{t40} = 0.2186 I_{t60} = 0.3279
3" X 6" Pressurizer Power Operated Relief Valve	-	I_{t40} = 0.16 I_{t60} = 0.24

[1] N_A and I_t were calculated for the design basis number of loading events applicable to the component that were originally intended to encompass a 40-year design life. The 60 year CUF (I_{t60}) were calculated by multiplying the 40 year CUF (I_{t40}) by 1.5 (60/40).

Disposition: Projection, 10 CFR 54.21 (c)(1)(ii); and Aging Management, 10 CFR 54.21(c)(1)(iii)

Projection of Fatigue - Valves with Margin

The calculated worst-case usage factors for the following valves indicate that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design lifetimes:

6" pressurizer safety relief valves,
6" hi-head safety injection pump discharge check valves,
8" hi-head safety injection pump discharge check valves,
8" lo-head safety injection to hot leg check valves,
8" lo-head safety injection to cold leg check valves,
12" safety injection to cold leg injection check valves,
12" safety injection accumulator outlet valves,
2" CVCS auxiliary spray check valves,
2" RCP seal injection first check valves, ~~and~~
2" RCP seal injection second check valves, and
3" X 6" pressurizer power operated relief valve

The design of these valves for fatigue effects is therefore valid for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii)

Aging Management - RHR Pump Suction Isolation Valves

The fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. Therefore the increase in operating life to 60 years will not have a significant effect on these fatigue usage factors so long as the number of transient cycles remains within the 40-year numbers of cycles assumed by the analysis.

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 4.3.1 and B3.1 ensures that the fatigue usage factors based on those transient events remain within the code limit of 1.0 for the period of extended operation, or that appropriate reevaluation or other corrective action is taken to maintain the design and licensing basis by other acceptable means. The effects of fatigue in Class 1 valve pressure boundaries will therefore be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.2.1.6 ASME III Class 1 Valves

STP Class 1 valves are designed to ASME III, Subsection NB, 1974 Edition with Summer 1975 addenda (pressurizer safety and control valves) or the 1974 Edition with Winter 1975 addendum (motor-operated, manual valves 3" and larger, and all valves 2" and smaller). ASME Section III requires a fatigue analysis only for Class 1 valves with an inlet piping connection greater than four inches nominal pipe size.

The calculated worst-case usage factors for the following valves indicate that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design lifetimes:

6" pressurizer safety relief valves,
6" hi-head safety injection pump discharge check valves,
8" hi-head safety injection pump discharge check valves,
8" lo-head safety injection to hot leg check valves,
8" lo-head safety injection to cold leg check valves,
12" safety injection to cold leg injection check valves,
12" safety injection accumulator outlet valves,
2" CVCS auxiliary spray check valves,
2" RCP seal injection first check valves, ~~and~~
2" RCP seal injection second check valves, and
3" X 6" pressurizer power operated relief valve

The design of these valves for fatigue effects is therefore valid for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

The fatigue usage factors in the RHR pump suction isolation valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. Therefore, the increase in operating life to 60 years will not have a significant effect on these fatigue usage factors so long as the number of transient cycles remains within the 40-year numbers of cycles assumed by the analysis.

The Metal Fatigue of Reactor Coolant Pressure Boundary program, described in Section A2.1, ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number; or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. The effects of fatigue will therefore be managed for the period of extended operation. This TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 3.2.1.50-1	Table 3.3.2-17
RAI 3.0-1	Table 3.3.2-17
RAI 3.3.1.92-01	Table 3.3.2-17

Table 3.3.2-17 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Damper	FB, PB	Carbon Steel (Galvanized)	Encased in Concrete (Ext)	None	None	VII.J-21	3.3.1.96	A
~~Damper~~	~~FB, PB~~	~~Carbon Steel (Galvanized)~~	~~Ventilation Atmosphere (Int)~~	~~None~~	~~None~~	~~VII.J-6~~	~~3.3.1.92~~	~~A~~
Damper	FB, PB	Carbon Steel (Galvanized)	Ventilation Atmosphere (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.F4-2	3.3.1.72	B
Filter (Halon)	PB	Aluminum	Dry Gas (Int)	None	None	VII.J-2	3.3.1.97	A
~~Filter (Halon)~~	~~PB~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	A
Filter (Halon)	PB	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.2.1.50	A
Filter (Halon)	FIL	Copper Alloy	Dry Gas (Int)	None	None	VII.J-4	3.3.1.97	A

Table 3.3.2-17 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve (Halon)	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	Fire Protection (B2.1.12)	VII.I-8	3.3.1.58	E, 2
~~Valve~~	~~PB~~	~~Carbon Steel~~	~~Fuel Oil (Int)~~	~~None~~	~~None~~	~~V.F-2~~	~~3.2.1.50~~	A

Valve	PB	Carbon Steel	Fuel Oil (Int)	Loss of material	Fuel Oil Chemistry (B2.1.14) & One Time Inspection (B2.1.16)	VII.H2-24	3.3.1.20	B
Valve	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B

RAI 3.1.1.80-1	LRA Sections 3.1.2.2.12 and 3.1.2.2.17 LRA Tables 3.1.1 and 3.1.2-1

3.1.2.2.12 Cracking due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

For managing the aging effect of cracking due to stress corrosion cracking and irradiation-assisted stress corrosion cracking of stainless steel reactor internals components exposed to reactor coolant, Water Chemistry (B2.1.2) is augmented by the plant-specific PWR Reactor Internals program (B2.1.35) based on the guidelines provided in EPRI 1016596 (MRP-227). Consistent with EPRI 1016596 (MRP-227), ~~cracking~~ PWR Reactor Internals (B2.1.35) is not an applicable aging ~~effect requiring~~ management program for managing cracking of the following components. Instead, cracking is managed by ASME Section XI Inservice Inspection (B2.1.1):

- RVI Hold Down Spring
- RVI Neutron Shield Panel
- RVI Upper Core Support-Upper Core Plate
- RVI Upper Core Support-Upper Support Column
- RVI Upper Core Support-Upper Support Column Base
- RVI Upper Core Support-Upper Support Plate
- RVI Control Rod Guide Tube Guide Plates
- RVI ICI Support Structures - Exit Thermocouples
- RVI ICI Support Structures - Upper/Lower Tie Plates
- RVI Irradiation Specimen Basket
- RVI Lower Core Support - Energy Absorber Assembly

3.1.2.2.17 Cracking due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

For managing the aging effect of cracking due to stress corrosion cracking, primary water stress corrosion cracking, and irradiation-assisted stress corrosion cracking of stainless steel reactor internals components exposed to reactor coolant, Water Chemistry program (B2.1.2) is augmented by the plant-specific PWR Reactor Internals program (B2.1.35) based on the guidelines provided in EPRI 1016596 (MRP-227). Consistent with EPRI 1016596 (MRP-227), PWR Reactor Internals (B2.1.35) ~~cracking~~ is not an applicable aging ~~effect requiring~~ management program for managing cracking of the following components. Instead, cracking is managed by ASME Section XI Inservice Inspection (B2.1.1):

- RVI Lower Core Support-Clevis Insert Bolting
- RVI Radial Support Keys and Clevis Inserts
- RVI Upper Support Column Bolting
- RVI Lower Core Support Bolts

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System (Continued)

3.1.1.30	Stainless steel reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Baffle/former assembly, Lower internal assembly, shroud assemblies, Plenum cover and plenum cylinder, Upper grid assembly, Control rod guide tube (CRGT) assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly, Thermal shield, Instrumentation support structures)	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking	Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No	~~Exception to NUREG-1801. Aging effect in NUREG-1801 for this material and environment combination is not applicable for selected components. See further evaluation in Section 3.1.2.2.12.~~Consistent with NUREG 1801 for material, environment, and aging effect, but different AMPs are credited: Water Chemistry program (B2.1.2) augmented by the plant-specific aging management program PWR Reactor Internals (B2.1.35). Consistent with EPRI 1016596 (MRP-227), cracking is managed by ASME Section XI Inservice Inspection for selected components.**See further evaluation in Section 3.1.2.2.12.

3.1.1.37	Stainless steel and nickel alloy reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Lower internal assembly, CEA shroud assemblies, Core shroud assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly)	Cracking due to stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking	Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No	~~Exception to NUREG-1801. Aging effect in NUREG-1801 for this material and environment combination is not applicable for selected components. See further evaluation in Section 3.1.2.2.17.~~ Consistent with NUREG 1801 for material, environment, and aging effect, but different AMPs are credited: Water Chemistry program (B2.1.2) augmented by the plant-specific aging management program PWR Reactor Internals (B2.1.35). Consistent with EPRI 1016596 (MRP-227), cracking is managed by ASME Section XI Inservice Inspection for selected components.**See further evaluation in Section 3.1.2.2.17.

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Control Rod Guide Tube Guide Plates	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-30	3.1.1.30	E, 5
RVI Hold Down Spring	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) ~~None~~	IV.B2-42	3.1.1.30	E ~~I~~, 5

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Hold Down Spring	SS	Stainless Steel	Reactor Coolant (Ext)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-34	3.1.1.63	C
RVI ICI Support Structures (Exit Thermocouple)	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-12	3.1.1.30	E, 5
~~RVI ICI Support Structures-Upper/Lower Tie Plates~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~PWR Reactor Internals (B2.1.35)~~	~~IV.B2-22~~	~~3.1.1.22~~	~~E, 3~~
RVI ICI Support Structures-Upper/Lower Tie Plates	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	~~Water Chemistry (B2.1.2) and PWR Reactor Internals (B2.1.35)~~ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-24	3.1.1.30	E, 5~~3~~
RVI Irradiation Specimen Basket	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-12	3.1.1.30	E, 5
RVI Lower Core Support Bolts	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	~~Water Chemistry (B2.1.2) and PWR Reactor Internals (B2.1.35)~~ ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-16	3.1.1.37	~~E, 3~~ E, 7

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Lower Core Support Bolts~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~PWR Reactor Internals (B2.1.35)~~	~~IV.B2-17~~	~~3.1.1.22~~	~~E, 3~~
~~RVI Lower Core Support Bolts~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of preload~~	~~PWR Reactor 0Internals (B2.1.35)~~	~~IV.B2-25~~	~~3.1.1.27~~	~~E, 3~~
RVI Lower Core Support-Clevis Insert Bolting	SS	Nickel Alloys	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) ~~None~~	IV.B2-16	3.1.1.37	~~I, 7~~ E, 7
RVI Lower Core Support-Energy Absorber Assembly	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-24	3.1.1.30	E, 5
RVI Neutron Shield Panel	SLD	Stainless Steel	Reactor Coolant (Ext)	Reactor Coolant (Ext) ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) ~~None~~	IV.B2-8	3.1.1.30	~~I, 5~~ E, 5
RVI Radial Support Keys and Clevis Inserts	SS	Nickel Alloys	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) ~~None~~	IV.B2-20	3.1.1.37	~~I, 7~~ E, 7
RVI Radial Support Keys and Clevis Inserts	SS	Stainless Steel	Reactor Coolant (Ext)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-34	3.1.1.63	C
RVI Upper Core Support-Protective Skirt	SS	Stainless Steel	Reactor Coolant (Ext)	None	None ~~PWR Reactor Internals (B2.1.35)~~	IV.B2-41	3.1.1.33	I, 4

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Upper Core Support-Upper Core Plate	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~Water Chemistry (B2.1.2) and PWR Reactor Internals (B2.1.35)~~	IV.B2-42	3.1.1.30	~~I, 5~~ E, 5
RVI Upper Core Support-Upper Support Column	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~None~~	IV.B2-36	3.1.1.30	~~I, 5~~ E, 5
RVI Upper Core Support-Upper Support Column Base	SS	Stainless Steel Cast Austenitic	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~None~~	IV.B2-36	3.1.1.30	~~I, 5~~ E, 5
RVI Upper Core Support-Upper Support Plate	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~None~~	IV.B2-42	3.1.1.30	~~I, 5~~ E, 5
RVI Upper Support Column Bolting	SS	Stainless Steel	Reactor Coolant (Ext)	Cracking ~~None~~	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~None~~	IV.B2-40	3.1.1.37	~~I, 7~~ E, 7

RAI 3.3.2.3.10-1	LRA Tables 3.3.2-10, 3.3.2-20

(See RAI 4.3-18 for changes to LRA Table 3.3.2-20)

Table 3.3.2-10 Auxiliary Systems – Summary of Aging Management Evaluation – Electrical Auxiliary Building and Control Room HVAC System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tubing	PB	Copper Alloy	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F2-14	3.3.1.25	E
~~Tubing~~	~~PB~~	~~Copper Alloy~~	~~Ventilation Atmosphere (Int)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~G~~
Tubing	PB	Copper Alloy	Ventilation Atmosphere (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.G-9	3.3.1.28	E
Tubing	PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A

Notes for Table 3.3.2-10:

Standard Notes:

A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

D Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program~~.~~

~~G Environment not in NUREG-1801 for this component and material.~~

H Aging effect not in NUREG-1801 for this component, material, and environment combination.

RAI 3.3.2.3.18-1	LRA Section 3.3.2.1.18 LRA Tables 2.3.3-18 and 3.3.2-18

3.3.2.1.18 Standby Diesel Generator Fuel Oil Storage and Transfer System

Materials

The materials of construction for the standby diesel generator fuel oil storage and transfer system component types are:

- Aluminum
- Carbon Steel
- Copper Alloy
- ~~Elastomer~~
- Stainless Steel

Environment

The standby diesel generator fuel oil storage and transfer system component types are exposed to the following environments:

- Atmosphere/ Weather
- Buried
- Fuel Oil
- Plant Indoor Air

Aging Effects Requiring Management

The following standby diesel generator fuel oil storage and transfer system aging effects require management:

- ~~Hardening and loss of strength~~
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the standby diesel generator fuel oil storage and transfer system component types:

- Bolting Integrity (B2.1.7)
- Buried Piping and Tanks Inspection (B2.1.18)
- External Surfaces Monitoring Program (B2.1.20)
- Fuel Oil Chemistry (B2.1.14)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
- One-Time Inspection (B2.1.16)

Table 2.3.3-18 Standby Diesel Generator Fuel Oil Storage and Transfer System

Component Type	Intended Function
Flame Arrestor	Pressure Boundary
~~Flexible Hoses~~	~~Pressure Boundary~~
Piping	Leakage Boundary (spatial) Pressure Boundary Structural Integrity (attached)

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator Fuel Oil Storage and Transfer System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flame Arrestor	PB	Aluminum	Fuel Oil (Int)	Loss of material	Fuel Oil Chemistry (B2.1.14) and One-Time Inspection (B2.1.16)	VII.H2-7	3.3.1.32	D
~~Flexible Hoses~~	~~PB~~	~~Elastomer~~	~~Fuel Oil (Int)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~G~~
~~Flexible Hoses~~	~~PB~~	~~Elastomer~~	~~Plant Indoor Air (Ext)~~	~~Hardening and loss of strength~~	~~External Surfaces Monitoring Program (B2.1.20)~~	~~VII.F4-6~~	~~3.3.1.11~~	~~E~~
Piping	LBS, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.H1-8	3.3.1.60	B

RAI 3.3.2.2.4-1	LRA Section 3.3.2.2.4.1

3.3.2.2.4 Cracking due to Stress Corrosion Cracking and Cyclic Loading

3.3.2.2.4.1 Stainless steel PWR non-regenerative heat exchanger components exposed to borated water

The Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.16) manage cracking due to stress corrosion cracking and cyclic loading for stainless steel letdown (non-regenerative) heat exchanger exposed to treated borated water. The one-time inspection will ~~include selected components at susceptible locations~~ perform eddy current inspection of the tubes in one of the non-regenerative heat exchangers.

Temperature and radioactivity of the shell-side water of the letdown (non-regenerative) heat exchanger is monitored continuously by installed plant instrumentation.

~~The One-Time Inspection program (B2.1.16) is selected in lieu of eddy current testing of tubes to provide confirmation that cracking is not occurring.~~ The continuous monitoring of temperature and radioactivity of the shell-side water together with one-time inspection provide early indication of cracking in the letdown (non-regenerative) heat exchanger prior to the loss of intended function.

RAI 3.4.2.2.4-1	LRA Section 3.4.2.2.4.1 and 3.4.2.2.4.2
RAI 3.4.2.2.4-2	LRA Section 3.4.2.2.4.1

3.4.2.2.4 Reduction of Heat Transfer due to Fouling

3.4.2.2.4.1 Stainless steel and copper alloy heat exchanger tubes exposed to treated water

The Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.16) manages loss of heat transfer due to fouling for ~~copper alloy~~ stainless steel components exposed to secondary water. The one-time inspection will include selected components at susceptible locations where contaminants could accumulate (e.g. stagnant flow locations).

3.4.2.2.4.2 Stainless steel and copper alloy heat exchanger tubes exposed to lubricating oil

The Lubricating Oil Analysis program (B2.1.23) and the One-Time Inspection program (B2.1.16) manages reduction of heat transfer due to fouling ~~copper alloy~~ stainless steel components exposed to lubricating oil. The one-time inspection will include selected components at susceptible locations where contaminants such as water could accumulate.

RAI 3.3.2.4-1	LRA Tables 3.3.2-6, 3.3.2-19, 3.3.2-20

(See RAI 4.3-18 for changes to LRA Tables 3.3.2-19 and 3.3.2-20)

Table 3.3.2-6 Auxiliary Systems – Summary of Aging Management Evaluation – Component Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (CCW Heat Exchanger)	PB	Copper Alloy	Raw Water (Int)	Loss of material	Open-Cycle Cooling Water System (B2.1.9)	VII.C1-3	3.3.1.82	B
~~Heat Exchanger (CCW Heat Exchanger)~~	~~HT, PB~~	~~Titanium~~	~~Closed Cycle Cooling Water (Ext)~~	~~None~~	~~None~~	~~None~~	~~None~~	~~F~~
Heat Exchanger (CCW Heat Exchanger)	HT, PB	Titanium	Closed Cycle Cooling Water (Ext)	Reduction of heat transfer	Closed-Cycle Cooling Water System (B2.1.10)	None	None	F
Heat Exchanger (CCW Heat Exchanger)	HT, PB	Titanium	Raw Water (Int)	Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.9)	None	None	F

RAI 3.0-1	LRA Tables 3.3.2-4, 3.3.2-17, 3.3.2-19, 3.3.2-20, 3.3.2-21, 3.3.2-27

(See RAI 3.2.1.50-1 for changes to Table 3.3.2-17. See RAI 4.3-18 for changes to Tables 3.3.2-19, 3.3.2-20 and 3.3.2-21. See RAI 3.3.2.3.22-1 for changes to Table 3.3.2-27)

Table 3.3.2-4 Auxiliary Systems – Summary of Aging Management Evaluation – Essential Cooling Water and ECW Screen Wash System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Flow Element	PB	Stainless Steel	Raw Water (Int)	Loss of material	Open-Cycle Cooling Water System (B2.1.9)	VII.C1-15	3.3.1.79	B
~~Heat Exchanger (CCW Pump Room)~~	~~HT~~	~~Aluminum~~	~~Plant Indoor Air (Ext)~~	~~None~~	~~None~~	~~VII.J-1~~	~~3.3.1.95~~	~~C~~
Heat Exchanger (CCW Pump Room)	HT	Aluminum	Plant Indoor Air (Ext)	None	None	V.F-2	3.2.1.50	C
Heat Exchanger (CCW Pump Room)	PB	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B

RAI 3.3.1.92-01	LRA Table 3.3.2-17 (See RAI 3.2.1.50-1 for changes to this Table)

RAI 3.1.2.2.16.1-1	LRA Section 3.1.2.16.1

3.1.2.2.16 Cracking due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

3.1.2.2.16.1 Steam generator heads, tubesheets, and welds made or clad with stainless steel

The CRDM head penetrations and housings, exit thermocouple penetration housing, internal disconnect device housing, and RVWLIS upper probe housing are made of stainless steel. For managing the aging effect of cracking due to stress corrosion cracking for stainless steel components exposed to reactor coolant, Water Chemistry program (B2.1.2) is augmented by ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD program (B2.1.1).

STP has recirculating steam generators, not once-through steam generators. Therefore, further evaluation 3.1.2.2.16.1 for the once-through steam generator components is not applicable to STP.

RAI 3.5.2.2.1.7-1	LRA Section 3.5.2.1.1, 3.5.2.2.1.7 LRA Table 3.5.2-1

3.5.2.1.1 Containment Building

Materials

The materials of construction for the containment building component types are:

- Carbon Steel
- Concrete
- Concrete Block (Masonry Walls)
- Elastomer
- Fire Barrier (Cementitious Coating)
- Stainless Steel
- Stainless Steel; Dissimilar Metal Welds

3.5.2.2.1.7 Cracking due to Stress Corrosion Cracking (SCC)

Cracking due to SCC is not an aging effect requiring management for STP stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. Both high temperature (> 140°F) and exposure to an aggressive environment are required for SCC to be applicable. At STP, these two conditions are not simultaneously present for any stainless steel penetration sleeves, bellows, or dissimilar metal welds. ~~Further~~ R~~r~~eview of STP plant-specific operating experience did not identify any SCC of these components.

The fuel transfer tube and associated expansion bellows are part of the containment pressure boundary. As such, they are within the scope of license renewal under the ASME Section XI, Subsection IWE program and the 10 CFR 50, Appendix J program. As discussed above, SCC is not expected to occur under the conditions present at STP, but these AMP's will continue to monitor these components to confirm the absence of aging effects.

Table 3.5.2-1 Containments, Structures, and Component Supports – Summary of Aging Management Evaluation - Containment Building

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bellows	ES, SPB, SS	Stainless Steel; <u>Dissimilar Metal Welds</u>	Plant Indoor Air (Structural) (Ext)	Cracking	ASME Section XI, Subsection IWE (B2.1.27) and 10 CFR Part 50, Appendix J (B2.1.30)	II.A3-2	3.5.1.10	B
Penetration	SLD, SPB, SS	Stainless Steel; <u>Dissimilar Metal Welds</u>	Plant Indoor Air (Structural) (Ext)	Cracking	ASME Section XI, Subsection IWE (B2.1.27) and 10 CFR Part 50, Appendix J (B2.1.30)	II.A3-2	3.5.1.10	B

RAI 4.1-4	LRA Table 3.4.2-1 (See RAI 4.3-18 for changes to this table)

RAI 4.1-7	LRA Section 4.1.4

4.1.4 Identification of Exemptions

10 CFR 54.21(c)(2) requires a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

Docketed correspondence, the operating license, and the UFSAR were searched to identify exemptions in effect. Each exemption in effect was then evaluated to determine whether it involved a TLAA as defined in 10 CFR 54.3.

Seven 10 CFR 50.12 exemptions "currently in effect" for STP were identified. Of those, ~~two~~three exemptions are based in part on time-limited aging analyses: (1) the use of the Leak-Before-Break (LBB) evaluation of reactor coolant system piping for STP Units 1 and 2;~~, and~~ (2) the use of ASME Code Case N-514 to establish the LTOP setpoints for Units 1 and 2; and (3) the partial exclusion of some components from the scope of special treatment requirements of 10 CFR Parts 21, 50, and 100 based on risk significance. ~~are based in part on a time-limited aging analysis~~. The LBB analysis is described in Section 4.3.2.11, *Fatigue Crack Growth Assessments and Fracture Mechanics Stability Analyses for Leak-Before-Break (LBB) Elimination of Dynamic Effects of Primary Loop Piping Failures*. The use of ASME Code Case N-514 is described in Section 4.2.5, *Low Temperature Overpressure Protection.* The partial exclusion based on risk significance is described in Section 4.4.