Attachment

RES STAFF COMMENTS ON

DRAFT

GENERIC AGING LESSONS LEARNED

(GALL) REPORT

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

Draft — December 6, 1999

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General Comments

1. Organization of columns in tables

It is recommended that the columns labeled as "Aging Effect" and "Aging Mechanisms" be switched. The switch would make a logical progression from "Materials" to "Environment" to "Aging Mechanisms" to "Aging Effects."

2. References

References cited in columns do not correlate one-on-one, with the "Region of Interest'. For example, in Section VI on Electrical Components, Page A-3, the Region of Interest is "conductor". While all cited references basically pertain to environmental qualification (EQ) in general, and specifically to insulating materials. It is desirable that for "conductors" references pertaining only to "conductors" be provided.

Many of the references cited in column 8 on individual components and structures are not included in the overall Reference sections at the end of the individual chapter. For completeness it is desirable to provide cross references.

3. Headings

Headings for columns on "Existing Aging Management Program (AMP)," "Evaluation and Technical Basis," and "Further Evaluation" do not match their respective structure or component under evaluation. It is recommended that headings for columns be made consistent with the structure or component under evaluation.

4. Column for "Existing Aging Management Program (AMP)"

The program description in the column should focus on the specific component or structure under evaluation and should not describe the program in generality.

5. Standard Review Plan and the GALL report

It would be of interest to know how the GALL report will be referenced in the SRP. Specifically, the treatment of augmented (△) programs for aging management for renewed license period.

6. Standard Review Plan and the GALL report

For a given component and structure under aging evaluation and for giving credit(s) to existing program(s) for aging management, it would be desirable to cross reference columns in the GALL report to appropriate corresponding sub-sections of the Standard Review Plan (SRP).

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Specific Comments

CHAPTER I

INTRODUCTION

Background

By letter dated March 3, 1999, the Nuclear Energy Institute (NEI) documented the industry's views on how existing plant programs and activities should be credited for license renewal. The "credit" issue was: to what extent should the staff review existing programs relied on for license renewal, to conclude that an applicant has demonstrated reasonable assurance that such programs will be effective in managing effects of aging on the functionality of structures and components in the period of extended operation. In a staff paper, SECY-99-148, "Credit for Existing Programs for License Renewal," dated June 3, 1999, the staff described options and provided a recommendation for crediting existing programs to improve the efficiency of the license renewal process.

By staff requirements memorandum (SRM) dated August 27, 1999, the Commission approved the staff's recommendation and directed the staff to focus the staff review guidance in the standard review plan (SRP) for license renewal on areas where existing programs should be augmented for license renewal. The staff would develop a "Generic Aging Lessons Learned (GALL)" report which evaluates existing programs generically to document the basis for determining when existing programs are adequate without change and when existing programs should be augmented for license renewal. The GALL report would be referenced in the SRP as a basis for determining the adequacy of existing programs.

GALL Report

This report builds on a previous report, NUREG/CR-6490, "Nuclear Power Plant Generic Aging Lessons Learned (GALL)," which is a systematic compilation of plant aging information. NUREG/CR-6490 was based on information in over 500 documents: Nuclear Plant Aging Research (NPAR) program reports sponsored by the Office of Nuclear Regulatory Research, Nuclear Management and Resources Council (NUMARC, now NEI) industry reports addressing license renewal, licensee event reports (LERs), information notices, generic letters, and bulletins.

The current effort reviews the aging effects on components and structures, identifies the relevant existing programs, and evaluates program attributes to manage aging effects for license renewal. This report is prepared with the technical assistance of the Argonne National Laboratory and the Brookhaven National Laboratory. As directed in the SRM, this report has the benefit of the experience from the staff members who conducted the review of the initial license renewal applications. Also, as directed in the SRM, the staff is seeking stakeholders' participation in the development of this report.

The results of the GALL effort are presented in a table format. The table column headings are: Item, Structure and Component, Region of Interest, Material, Environment, Aging Effects, Aging Mechanism, References, Existing Aging Management Program, Evaluation and Technical Basis, and Further Evaluation. Program attributes are evaluated for their adequacy in managing certain aging effects for particular structures and components. The evaluation is based on the review of these 10 attributes: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. If the evaluation determines that a program is adequate to manage certain aging effects for a particular structure and component without change, the "Further Evaluation" entry would indicate no further staff evaluation is recommended for license renewal. Otherwise, it would recommend area(s) where the staff should focus its review.

Application of GALL Report

The GALL report is a basis document to the SRP that provides staff guidance in reviewing a license renewal application. License renewal applicants would submit information on specific existing programs that are relied on to manage certain aging effects for particular structures and components and would reference the GALL report as basis for program adequacy. The staff would follow the guidance in the SRP to verify that the applicants have identified the appropriate existing programs. The main focus of the staff review would be on augmented programs for license renewal. The SRP incorporating the GALL report is to be developed.

CHAPTER II

CONTAINMENT STRUCTURES

Major Containment Structures

A. **Pressurized Water Reactor (PWR) Containments**

B. **Boiling Water Reactor (BWR) Containments**

CHAPTER II A

PRESSURIZED WATER REACTOR (PWR) CONTAINMENTS

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as A1.2, Corrosion Aging Mechanism NUREG-1611 identifies stress corrosion cracking of the steel liner as non-significant.	This aging effect is not significant for the liner itself. See Item A3.1.	No.
Same as A1.1, Freeze/Thaw Aging Mechanism Note: 10CFR50.55a and IWL do not apply to bonded post-tensioning systems. NUREG-1611 identifies 10CFR50.55a/IWL for managing tendon and anchor corrosion.	*Same as A1.1, Freeze/Thaw Aging Mechanism* 3/17/00 Add the following: IWL provides for monitoring the bearing plates and anchoring components. If the condition and environment of the tendon access gallery may lead to degradation of these components.	No.
NUREG-1522 and IN 99-10 describe conditions in tendon access galleries conducive to corrosion of tendon anchorage components	Managing the condition and environment in the tendon access gallery (e.g., moisture and humidity) is a prudent way to manage the degradation (i.e., corrosion) of bearing plates and other vertical tendon anchorage components	Yes. Plant-specific consideration of the tendon access gallery should be evaluated.

Concrete Containments," April 13, 1999.

NRC Regulatory Guide 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments," July 1990.

NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995.

NRC Draft Regulatory Guide DG-1076, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," February 1999.

NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Power Plant Structures," June 1995.

NUREG-1611, "Aging Management of Nuclear Power Plant Containments for License Renewal," September 1997.

Nuclear Energy Institute, NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10CFR Part 50, Appendix J," Revision 0, July 26, 1995.

Add →

NRC Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments," July 1990.

CHAPTER II B

BOILING WATER REACTOR (BWR) CONTAINMENTS

CHAPTER III

STRUCTURES
AND
COMPONENT SUPPORTS

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CHAPTER III A

CLASS 1 STRUCTURES

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
IE Bulletin 80-11 **IN No. 87-67:** The IE Bulletin No.80-11 titled "Masonry Wall Design" was issued to address the concern with regard to the adequacy of the design criteria used in the design of masonry walls and the apparent lack of design criteria coordination between the structural and piping/equipment design groups. It required all operating nuclear power plants to address this issue by 1) identifying all masonry walls in close proximity or having attachments from safety-related piping or equipment, and 2) performing reevaluation of design adequacy of the walls and the construction practices employed in the construction of these walls. The NRC Information Notice (IN) No. 87-67 titled "Lessons Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11"documented the inspection experience conducted by the NRC staff with respect to plant-specific implementation and corrective actions in executing the IE Bulletin 80-11 requirements. During the inspections performed at several plants, a number of deficiencies having the potential for affecting plant safety were identified. In each case of the identified deficiencies, remedial action was required by the licensee. The IN No. 87-67 concluded that the recurring nature of some of the observed cracks may justify the need for a periodic surveillance program to ensure that the level of structural adequacy to which licensees committed is maintained. Applicant should develop a program with procedural controls requiring engineering notification, reevaluation, and periodic inspections to ensure that the structural integrity of these walls is maintained. IN No. 87-67 states that these programs ensure that the physical condition of the walls, such as lack of mortar cracking and boundary conditions, remain as analyzed. Therefore, a periodic inspection and surveillance program instituted by the licensee in accordance with the insights provided in IN No. 87-67, constitutes part of a aging management program for masonry walls that were covered by IE Bulletin 80-11. Such program, if properly managed, should provide reasonable assurance that any recurrence of aged-related deficiencies (e.g. mortar cracks) that could potentially compromise masonry wall's intended	***(1) Scope of Program:*** The IE Bulletin 80-11 and IN No. 87-67 apply to all masonry walls which are in proximity to or having attachments from safety-related piping or equipment such that wall failure could affect a safety-related system. However, during the implementation of USI A-46, numerous instances of masonry walls which are important to safety but not covered by the IE Bulletin 80-11 were identified, due to either reclassification of non-safety-related system to safety-related, or falling of non-safety-related system onto safety-related systems. In these cases, if the verification can be established that the masonry walls were evaluated and maintained in accordance with the requirements of the IE Bulletin 80-11 and the insights provided by the IN No. 87-67, the subject walls should be treated as within the scope encompassed by the IE Bulletin 80-11 and IN No. 87-67. ***(2) Preventive Actions:*** The IN No. 87-67 called for a periodic surveillance program by the licensee to monitor any specific conditions (e.g. mortar cracks) of masonry walls to ascertain that the level of structural adequacy to which licensees committed is maintained. It also suggested that the licensee's periodic surveillance program for managing the effects of cracking in masonry walls should include: 1) an analysis of the probable cause of the cracks; 2) documentation of the repair efforts for these cracks or a demonstration of the structural adequacy of the walls, including the effects of the cracked block and mortar; and 3) a description of the measures to be taken to prevent recurrence of similar cracking in these and other safety-related masonry walls that are not reinforced. However, no specific interval for the periodic inspection was suggested by the IN No. 87-67. 10 CFR 50.65(a) Paragraph 3 requires that the effectiveness of maintenance programs be assessed at least every two years. ***(3) Parameters Monitored/Inspected:*** The IN No. 87-67 identified cracks in masonry walls, especially unreinforced walls, as being the primary age-related degradation mechanisms for masonry wall structures as encompassed in Scope, and discussed the extent to which the age-related degradation mechanisms impact the intended functions of the safety-related piping or equipment being supported by the walls, if the effects of aging-related degradation of masonry walls are left undetected, uncorrected and unmanaged. ***(4) Detection:*** If properly conducted, inspection programs following the IE Bulletin 80-11 and IN No. 87-67 should provide reasonable assurance that any recurrence of aged-related deficiencies (e.g. mortar cracks) that could potentially compromise a masonry wall's intended functions will be identified. ***(5) Monitoring and Trending:*** The IN No. 87-67 suggested periodic surveillance to monitor any specific conditions (e.g. mortar cracks) of masonry walls to ascertain that the level of structural adequacy to which licensees committed is maintained, and abnormalities affecting facility safety identified by the surveillance program should be met with corresponding corrective action. The periodic inspections should also provide predictability of the extent of age-related degradation.	No. Acceptable for managing aging effect.

III STRUCTURES AND COMPONENT SUPPORTS

A2. Group 2 Structures (BWR reactor building with steel superstructure)

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as A1.1, Settlement Aging Mechanism	*Same as A1.1, Settlement Aging Mechanism*	*Same as A1.1, Settlement Aging Mechanism*
Same as A1.1, Erosion of Porous Concrete Subfoundation Aging Mechanism	*Same as A1.1, Erosion of Porous Concrete Subfoundation Aging Mechanism*	*Same as A1.1, Erosion of Porous Concrete Subfoundation Aging Mechanism*
Same as A1.2, Corrosion Aging Mechanism	*Same as A1.2, Corrosion Aging Mechanism* Note: Per NUREG-1557, aging management of the metal siding, grating, and roofing for loss of material due to corrosion is an unresolved issue.	*Same as A1.2, Corrosion Aging Mechanism*
Same as A1.3, Cracking due to Restraint; Shrinkage; Creep; Aggressive Environment	*Same as A1.3, Cracking due to Restraint; Shrinkage; Creep; Aggressive Environment*	*Same as A1.3, Cracking due to Restraint; Shrinkage; Creep; Aggressive Environment*

CHAPTER III B

COMPONENT SUPPORTS

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Maintenance Rule (10CFR50.65) -Structures monitoring The "Maintenance Rule" is intended to monitor the effectiveness of maintenance activities in nuclear power plants. It focuses on the adequacy of preventive and corrective maintenance activities. 10CFR50.65 requires each licensee to develop and implement a program to verify that the current licensing basis (CLB) is maintained through periodic testing and inspection of critical plant structures, systems, and components. The nuclear power industry, through the Nuclear Energy Institute (NEI), has developed guidance for the development of such programs. Rev. 2 to NUMARC 93-01 was issued in April 1996. USNRC Regulatory Guide 1.160, Rev. 2, issued in March 1997, identifies this document as an acceptable approach to meeting the objectives of 10CFR50.65. Revision 2 to NUMARC 93-01 added Section 10.2.3, "Monitoring the Condition of Structures." It emphasizes the importance of monitoring the condition of plant structures. Quoting from this report, "Monitoring the condition of structures, like systems and components, should be predictive in nature and provide early warning of degradation. The baseline condition of plant structures should be established to facilitate condition monitoring activities." Regulatory Position 1.5 "Monitoring of Structures" in RG1.160, Rev. 2, states that the Maintenance Rule does not treat structures differently from systems and components. The attributes of an acceptable structure monitoring program are discussed. Structures Monitoring Programs developed to meet the requirements of 10CFR50.65 (Maintenance Rule) can be credited for addressing aging management of structures and structural components to meet the requirements of 10CFR54 (License Renewal). License	An applicant for License Renewal may reference its Structures Monitoring Program developed to meet the requirements of the Maintenance Rule (10CFR50.65), as further defined and clarified by NUMARC 93-01, Revision 2 and Regulatory Guide 1.160, Revision 2. The guidelines contained in these documents provide an adequate foundation for formulating licensee-specific MR Structures Monitoring Programs. An applicant for License Renewal should confirm that its MR Structures Monitoring Program adequately manages the effects of aging so that the intended functions of structures and component supports will be maintained, consistent with the current licensing basis, for the period of extended operation. The applicant should assess its MR Structures Monitoring Program against the attributes of an acceptable aging management program. Evaluation of MR Structures Monitoring against the ten (10) criteria for an acceptable aging management program follows: **(1)Scope of Program:** The MR Structures Monitoring Program scope is defined by the licensee; it may or may not encompass all structures and structural components which must be reviewed for License Renewal. The applicant should clearly identify the structure/aging effect/aging mechanism combinations which are managed by the MR Structures Monitoring Program. For potential structure/aging effect/aging mechanism combinations not covered by the MR Structures Monitoring Program, the applicant should justify that it is not significant for the applicant's plant, or identify the applicable aging management program. **(2) Preventive Actions:** Inspection and maintenance of protective coatings which inhibit corrosion of steel structural elements should be included as part of Structures Monitoring. No specific preventive actions are identified for other aging mechanisms. **(3) Parameters Monitored/Inspected:** For MR Structures Monitoring Programs, specification of the parameters monitored or inspected is the responsibility of the licensee. For License Renewal, the specific parameters monitored or inspected should be linked to degradation of intended function(s) and should detect the presence and extent of aging effects. The inspection scope should include bolt-tightness checks for concrete expansion anchors subjected to vibratory loads. The applicant should confirm that its specification of parameters to be monitored or inspected is consistent with meeting Criterion 3. **(4) Detection of Aging Effects:** Detection of aging effects before there is loss of intended function requires that periodic inspection be conducted, utilizing appropriate inspection methods implemented by qualified inspectors. Under the Maintenance Rule, the inspection schedule, inspection methods and inspector qualifications are defined by the individual licensees. An applicant for License Renewal should confirm that these elements of its MR Structures Monitoring Program are consistent with meeting Criterion 4.	No, if within the scope of the applicant's MR Structures Monitoring Program. Otherwise, justification for non-applicability or details of plant-specific program need to be evaluated. *and unistrut or similar structural elements for corrosion or loss of galvanized coatings.*

B4 Supports for Miscellaneous Mechanical Equipment (e.g., Cranes, EDG, HVAC System Components)

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Maintenance Rule (10CFR50.65) -Structures monitoring The "Maintenance Rule" is intended to monitor the effectiveness of maintenance activities in nuclear power plants. It focuses on the adequacy of preventive and corrective maintenance activities. 10CFR50.65 requires each licensee to develop and implement a program to verify that the current licensing basis (CLB) is maintained through periodic testing and inspection of critical plant structures, systems, and components. The nuclear power industry, through the Nuclear Energy Institute (NEI), has developed guidance for the development of such programs. Rev. 2 to NUMARC 93-01 was issued in April 1996. USNRC Regulatory Guide 1.160, Rev. 2, issued in March 1997, identifies this document as an acceptable approach to meeting the objectives of 10CFR50.65. Revision 2 to NUMARC 93-01 added Section 10.2.3, "Monitoring the Condition of Structures." It emphasizes the importance of monitoring the condition of plant structures. Quoting from this report, "Monitoring the condition of structures, like systems and components, should be predictive in nature and provide early warning of degradation. The baseline condition of plant structures should be established to facilitate condition monitoring activities." Regulatory Position 1.5 "Monitoring of Structures" in RG1.160, Rev. 2, states that the Maintenance Rule does not treat structures differently from systems and components. The attributes of an acceptable structure monitoring program are discussed. Structures Monitoring Programs developed to meet the requirements of 10CFR50.65 (Maintenance Rule) can be credited for addressing aging management of structures and structural components to meet the requirements of 10CFR54 (License Renewal). License	An applicant for License Renewal may reference its Structures Monitoring Program developed to meet the requirements of the Maintenance Rule (10CFR50.65), as further defined and clarified by NUMARC 93-01, Revision 2 and Regulatory Guide 1.160, Revision 2. The guidelines contained in these documents provide an adequate foundation for formulating licensee-specific MR Structures Monitoring Programs. An applicant for License Renewal should confirm that its MR Structures Monitoring Program adequately manages the effects of aging so that the intended functions of structures and component supports will be maintained, consistent with the current licensing basis, for the period of extended operation. The applicant should assess its MR Structures Monitoring Program against the attributes of an acceptable aging management program. Evaluation of MR Structures Monitoring against the ten (10) criteria for an acceptable aging management program follows: **(1)Scope of Program:** The MR Structures Monitoring Program scope is defined by the licensee; it may or may not encompass all structures and structural components which must be reviewed for License Renewal. The applicant should clearly identify the structure/aging effect/aging mechanism combinations which are managed by the MR Structures Monitoring Program. For potential structure/aging effect/aging mechanism combinations not covered by the MR Structures Monitoring Program, the applicant should justify that it is not significant for the applicant's plant, or identify the applicable aging management program. **(2) Preventive Actions:** Inspection and maintenance of protective coatings which inhibit corrosion of steel structural elements should be included as part of Structures Monitoring. No specific preventive actions are identified for other aging mechanisms. **(3) Parameters Monitored/Inspected:** For MR Structures Monitoring Programs, specification of the parameters monitored or inspected is the responsibility of the licensee. For License Renewal, the specific parameters monitored or inspected should be linked to degradation of intended function(s) and should detect the presence and extent of aging effects. The inspection scope should include bolt-tightness checks for concrete expansion anchors subjected to vibratory loads [and unistrut or similar structural elements for corrosion or loss of galvanized coatings]. The applicant should confirm that its specification of parameters to be monitored or inspected is consistent with meeting Criterion 3. **(4) Detection of Aging Effects:** Detection of aging effects before there is loss of intended function requires that periodic inspection be conducted, utilizing appropriate inspection methods implemented by qualified inspectors. Under the Maintenance Rule, the inspection schedule, inspection methods and inspector qualifications are defined by the individual licensees. An applicant for License Renewal should confirm that these elements of its MR Structures Monitoring Program are consistent with meeting Criterion 4.	No, if within the scope of the applicant's MR Structures Monitoring Program. Otherwise, justification for non-applicability or details of plant-specific program need to be evaluated.

CHAPTER IV

(12/06/99)

REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

Major Plant Sections

A1. Reactor Vessel (Boiling Water Reactor)

A2. Reactor Vessel (Pressurized Water Reactor)

B1. Reactor Vessel Internals (Boiling Water Reactor)

B2. Reactor Vessel Internals (PWR) - Westinghouse

B3. Reactor Vessel Internals (PWR) - Combustion Engineering)

B4. Reactor Vessel Internals (PWR) - Babcock & Wilcox

C1. Reactor Coolant Pressure Boundary (Boiling Water Reactor)

C2. Reactor Coolant System and Connected Lines (Pressurized Water Reactor)

D1. Steam Generator (Recirculating)

D2. Steam Generator (Once-Through)

A1. Reactor Vessel (Boiling Water Reactor)

A1.1 Top Head Enclosure

A1.1.1 Top Head

A1.1.2 Nozzles (Vent, Top Head Spray or RCIC, and Spare)

A1.1.3 Head Flange

A1.1.4 Closure Studs and Nuts

A1.1.5 Vessel Flange Leak Detection Line

A1.2 Vessel Shell

A1.2.1 Vessel Flange

A1.2.2 Upper Shell

A1.2.3 Intermediate (Nozzle) Shell

A1.2.4 Intermediate (Beltline) Shell

A1.2.5 Lower Shell

A1.2.6 Beltline Welds

A1.2.7 Attachment Welds

A1.3 Nozzles

A1.3.1 Main Steam

A1.3.2 Feedwater

A1.3.3 High Pressure Coolant Injection (HPCI)

A1.3.4 High Pressure Core Spray (HPCS)

A1.3.5 Low Pressure Core Spray (LPCS)

A1.3.6 CRD Return Line

A1.3.7 Recirculating Water (Inlet & Outlet)

A1.3.8 Low Pressure Coolant Injection (LPCI) or RHR Injection Mode

A1.3.9 Isolation Condenser Supply

A1.4 Nozzles Safe Ends

A1.4.1 High Pressure Core Spray (HPCS)

A1.4.2 Low Pressure Core Spray (LPCS)

A1.4.3 CRD Return Line

A1.4.4 Recirculating Water (Inlet & Outlet)

A1.4.5 Low Pressure Coolant Injection (LPCI) or RHR Injection Mode

A1.5 Penetrations

A1.5.1 CRD Stub Tubes

A1.5.2 Instrumentation

A1.5.3 Jet Pump Instrument

A1.5.4 Standby Liquid Control

A1.5.5 Flux Monitor

A1.5.6 Drain Line

A1.6 Bottom Head

A1.7 Control Rod Drive Mechanism

A1.7.1 Housing

A1.8 Support Skirt and Attachment Welds

A2. Reactor Vessel (Pressurized Water Reactor)

- A2.1 Closure Head
  - A2.1.1 Dome
  - A2.1.2 Head Flange
  - A2.1.3 Stud Assembly
  - A2.1.4 Vessel Flange Leak Detection Line
- A2.2 Control Rod Drive Mechanism
  - A2.2.1 Pressure Housing
- A2.3 Nozzles
  - A2.3.1 Inlet
  - A2.3.2 Outlet
  - A2.3.3 Safety Injection (on some)
- A2.4 Nozzle Safe Ends
  - A2.4.1 Inlet
  - A2.4.2 Outlet
  - A2.4.3 Safety Injection (on some)
- A2.5 Shell
  - A2.5.1 Upper (Nozzle) Shell
  - A2.5.2 Intermediate & Lower Shell
  - A2.5.3 Vessel Flange
- A2.6 Core Support Pads
- A2.7 Bottom Head
  - A2.7.1 Dome
- A2.8 Penetrations

A2.8.1 CRD Mechanism

A2.8.2 Instrumentation

A2.8.3 Leakage Monitoring Tubes

A2.9 Pressure Vessel Support

A2.9.1 Skirt Support

A2.9.2 Cantilever/Column Support

A2.9.3 Neutron Shield Tank

B1. Reactor Vessel Internals (Boiling Water Reactor)

B1.1 Core Shroud, Shroud Head, and Core Plate

B1.1.1 Core Shroud Head Bolts

B1.1.2 Core Shroud (Upper, Central, Lower)

B1.1.3 Core Plate

B1.1.4 Core Plate Bolts

B1.1.5 Access Hole Cover

B1.1.6 Shroud Support Structure

B1.1.7 Standby Liquid Control Line

B1.1.8 LPCI Coupling

B1.2 Top Guide

B1.3 Feedwater Spargers

B1.3.1 Thermal Sleeve

B1.3.2 Distribution Header

B1.3.3 Discharge Nozzles

B1.4 Core Spray Lines and Spargers

B1.4.1 Core Spray Lines (Headers)

B1.4.2 Spray Ring

B1.4.3 Spray Nozzles

B1.4.4 Thermal Sleeve

B1.5 Jet Pump Assemblies

B1.5.1 Thermal Sleeve

B1.5.2 Inlet Header

B1.5.3 Riser Brace Arm

B1.5.4 Holddown Beams

B1.5.5 Inlet Elbow

B1.5.6 Mixing Assembly

B1.5.7 Diffuser

B1.5.8 Castings

B1.6 Fuel Supports & CRD Assemblies

B1.6.1 Orificed Fuel Support

B1.7 Instrument Housings

B1.7.1 Intermediate Range Monitor (IRM) Dry Tubes

B1.7.2 Low Power Range Monitor (LPRM) Dry Tubes

B1.7.3 Source Range Monitor (SRM) Dry Tubes

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
B1.1.5	Core Shroud, Shroud Head and Core Plate	Access Hole Cover	Alloy 600, Alloy 82 & 182 welds	288°C, High-Purity Water	Crack Initiation and Growth	SCC IASCC	ASME Section XI, 1989 Edition. GE SIL 462 Sup. 3. BWRVIP-29. EPRI TR-103515.
B1.1.6	Core Shroud, Shroud Head and Core Plate	Shroud Support Structure (Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs)	Alloy 600, Alloy 82 & 182 welds	288°C, High-Purity Water	Crack Initiation and Growth	SCC	ASME Section XI, 1989 Edition. GE SIL 462 Sup. 3. BWRVIP-29. EPRI TR-103515. BWRVIP-38. BWRVIP-52. *Supporting BWRVIP:* BWRVIP-03. BWRVIP-06. BWRVIP-14. BWRVIP-44. BWRVIP-45. BWRVIP-59. BWRVIP-60. BWRVIP-62. *Operating Experience* NRC IN 88-03. NRC IN 92-57.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Stress Corrosion Cracking on Item B1.1.6 shroud support structure.	*Same as for the effect of Stress Corrosion Cracking on Item B1.1.6 shroud support structure.*	Yes, BWRVIP Guideline
Visual inspection (VT-3) is performed according to ASME Section XI, IWB-2500, category B-N-2. Guidance for enhanced VT-1 inspections and UT inspections in plant specific programs. Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. Plant programs also may include water chemistry measures such as strict controls on conductivity, hydrogen addition, and use of noble metal additions to reduce electrochemical potential. BWRVIP guideline is under staff review.	***(1) Scope of Program:*** The program includes preventive measures to mitigate SCC, inservice inspection (ISI) to monitor the effects of SCC on the intended function of the components, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** Maintaining high water purity (many BWRs now operate at <0.15 μS/cm^2) reduces susceptibility to SCC. Hydrogen additions are effective in reducing electrochemical potentials in the recirculation piping system, but are less effective in the core region. Noble metal additions through a catalytic action ~~appear to~~ increase the effectiveness of hydrogen additions in the core region. ~~but only limited data are available at present to demonstrate their effectiveness~~. ***(3) Parameters Monitored/ Inspected:*** Inspection and flaw evaluation are to be performed in accordance with referenced BWRVIP guideline, as approved by the NRC staff. ***(4) Detection of Aging Effects:*** Degradation due to SCC can not occur without crack initiation and growth. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with applicable, approved BWRVIP guideline is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with applicable, approved BWRVIP guideline. ***(7) Corrective Actions:*** The corrective action proposed by the BWRVIP is under staff review. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Cracking has occurred in a number of vessel internal components. Weld regions are most susceptible, although it is not clear whether this is due to sensitization and/or impurities associated with the welds or the high residual stresses in the weld regions.	Yes, BWRVIP Guideline
Same as for the effect of Stress Corrosion Cracking on Item B1.1.7 standby liquid control line.	*Same as for the effect of Stress Corrosion Cracking on Item B1.1.7 standby liquid control line.*	Yes, BWRVIP Guideline
Visual inspection (VT-3) is performed according to ASME Section XI, IWB-2500, category B-N-2. Guidance for enhanced VT-1 inspections and UT inspections in plant specific programs. Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. Plant	***(1) Scope of Program:*** The program includes preventive measures to mitigate SCC, inservice inspection (ISI) to monitor the effects of SCC on the intended function of the components, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** Maintaining high water purity (many BWRs now operate at <0.15 μS/cm^2) reduces susceptibility to SCC. Hydrogen additions are effective in reducing electrochemical potentials in the recirculation piping system, but are less effective in the core region.	Yes, BWRVIP Guideline

B2. Reactor Vessel Internals (PWR) - Westinghouse

B2.1 Upper Internals Assembly

B2.1.1 Upper Support Plate

B2.1.2 Upper Support Column

B2.1.3 Upper Support Column Bolts

B2.1.4 Upper Core Plate

B2.1.5 Upper Core Plate Alignment Pins

B2.1.6 Fuel Pins

B2.1.7 Hold-Down Spring

B2.2 RCCA Guide Tube Assemblies

B2.2.1 RCCA Guide Tubes

B2.2.2 RCCA Guide Tube Bolts

B2.2.3 RCCA Guide Tube Support Pins

B2.3 Core Barrel

B2.3.1 Core Barrel

B2.3.2 Upper Core Barrel Flange

B2.3.3 Core Barrel Nozzles

B2.3.4 Thermal Shield

B2.4 Baffle/Former Assembly

B2.4.1 Baffle/Former Plates

B2.4.2 Baffle/Former Bolts

B2.5 Lower Internal Assembly

B2.5.1 Lower Core Plate

B2.5.2 Fuel Pins

B2.5.3 Lower Support Plate

B2.5.4 Lower Support Plate Column

B2.5.5 Lower Support Plate Column Bolts

B2.5.6 Radial Keys and Clevis Inserts

B2.5.7 Clevis Insert Bolts

B2.6 Instrumentation Support Structure

B2.6.1 Flux Thimble Guide Tubes

B2.6.2 Flux Thimbles

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI (edition specified in 10 CFR 50.55a). Primary water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-105714 to minimize the potential of crack initiation and growth.	***(1) Scope of Program:*** The program includes preventive measures to mitigate SCC of SS components, inservice inspection (ISI) to monitor the effects of SCC on the intended function of the components, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** PWR operating chemistry limits the halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation. However, introduction of oxygen can occur during shutdown and potential exists for the formation of more aggressive chemistry conditions by radiolysis in creviced regions or in low-flow stagnant regions. The AMP must rely upon inservice inspection (ISI) in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of SCC on the intended function by detection and sizing of cracks by ISI. Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** Degradation due to SCC can not occur without crack initiation and growth. VT-3 may not be adequate to detect tight cracks. Creviced and other inaccessible regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although stainless steel components in PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, potential for SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84-18), from the introduction of relatively high levels of dissolved oxygen during shutdown, or from aggressive chemistries that may develop in creviced regions. Cracking has occurred in SS baffle former bolts in a number of foreign plants (IN 98-11) and has now been observed in US plants. The mechanism of this particular cracking has not yet been resolved.	Yes Element 4 should be further evaluated
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI (edition specified in 10 CFR 50.55a). Primary water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-105714 to minimize the potential of crack initiation and growth.	***(1) Scope of Program:*** The program includes preventive measures to mitigate SCC of SS components, inservice inspection (ISI) to monitor the effects of SCC on the intended function of the components, and repair and/or replacement as needed to maintain the capability to perform the intended function.. ***(2) Preventive Actions:*** PWR operating chemistry limits the halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, which	Yes Element 4 should be further evaluated

IASCC can occur even for good water chemistry for high radiation damage levels.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) greatly reduces susceptibility to IASCC. However, introduction of oxygen can occur during shutdown and potential exists for the formation of more aggressive chemistry conditions by radiolysis in creviced regions or in low–flow stagnant regions. Also for sufficiently high fluence levels, IASCC can occur even in low oxygen environments. The AMP must rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on the intended function by detection and sizing of cracks by inservice inspection (ISI). Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** Degradation due to IASCC can not occur without crack initiation and growth. VT-3 may not be adequate to detect tight cracks. The inspection technique, including the reliability in detecting the features of interest (crack appearance and size) in assuring the integrity of the component, should be specified. For example, enhancement of the visual VT-1 examination to achieve a 1/2-mil (0.0005 in.) resolution, with the conditions (lighting and surface cleanness) for the ISI bounded by those used to demonstrate the resolution of the inspection technique. Creviced regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. As an alternate to enhanced inspection, perform a component-specific evaluation including a mechanical loading assessment to determine the maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the only cracking presently directly attributable to IASCC in PWRs occurred in SS fuel cladding used in early reactors, susceptibility to this degradation will increase as plant operating time and hence accumulated fluence levels increase. The role that IASCC has played in the more recent cracking that has occurred in SS baffle/former bolts in U.S. plants as well as foreign plants (IN 98-11) in not yet universally agreed upon.	
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. The applicant should address ~~embrittlement~~ loss of ductility associated with swelling.	Yes TLAA

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) internals. ***(4) Detection of Aging Effects:*** Degradation due to SCC can not occur without crack initiation and growth. Historically the VT-3 visual examinations have not identified bolt cracking because cracking occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. Creviced and other inaccessible regions are difficult to inspect visually. Supplementary UT examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although stainless steel components in PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, potential for SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84-18), from the introduction of relatively high levels of dissolved oxygen during shutdown, or from aggressive chemistries that may develop in creviced regions. Cracking has occurred in SS baffle former bolts in a number of foreign plants (IN 98-11) and has now been observed in US plants. The mechanism of this particular cracking has not yet been resolved. SCC has also been observed in Ni alloy (Alloy X-750) control rod drive guide tube support pins (IN 82-29). Replacement components with a different heat treatment appear to be less susceptible to cracking.	
Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. The applicant should address ~~embrittlement~~ loss of ductility, associated with swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as the effect of Stress Relaxation on Item B2.1.7, hold-down spring.*	Yes Elements 3 and 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. The applicant should address loss of ductility associated with swelling	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	***(1) Scope of Program:*** The program includes inservice inspection (ISI) to detect cracking and/or failure, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** No practical preventative actions are possible. Stainless steels are susceptible to embrittlement under neutron irradiation. Fracture toughness will depend strongly on the fluence on a particular component. Components can be screened out if the maximum tensile loading on the component under ASME Code Level A, B, C, and D conditions is sufficiently low. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of neutron irradiation embrittlement on the intended function of the component by detection and sizing of cracks by inservice inspection (ISI). Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** ~~Loss of fracture toughness is of consequence only if cracks exist~~. Cracking is expected to initiate at the surface and should be detectable by ISI except for some crevice regions. VT-3 may not be adequate to detect tight cracks. Also, creviced regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** No instances of internals degradation have been recorded that have been definitely attributed to irradiation embrittlement.	Yes Elements 3 and 4 should be further evaluated
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B2.1.5 upper core plate alignment pins and B2.1.6 fuel pins.*	No

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Plant-specific aging management program. Historically the VT-3 visual examinations have not identified baffle/former bolt cracking because cracking occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. However, recent UT examinations of the baffle/former bolt have identified cracking in several plants. The industry is currently addressing the issue of baffle bolt cracking in the PWR Materials Reliability Project, Issues Task Group (ITG) activities to determine, develop, and implement the necessary steps and plans to manage the applicable aging effects on a plant specific basis.	Plant-specific aging management program is to be evaluated.	Yes No AMP
Same as for the effect of Stress Corrosion Cracking on Item B2.4.2 baffle/former bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B2.4.2 baffle/former bolts.*	Yes No AMP
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP.	Yes TLAA

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B2.3.1 thru B2.3.3 core barrel, upper core barrel flange, core barrel nozzles.*	Yes Elements 3 and 4 should be further evaluated
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B2.1.7 hold-down spring.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B2.3.1 thru B2.3.3 core barrel, upper core barrel flange, core barrel nozzles.*	Yes Elements 3 and 4 should be further evaluated
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.*	Yes Element 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.3 upper support column bolts, B2.1.5 upper core plate alignment pins, and B2.1.6 fuel pins.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B2.3.1 thru B2.3.3 core barrel, upper core barrel flange, core barrel nozzles.*	Yes Elements 3 and 4 should be further evaluated
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B2.1.7 hold-down spring.*	Yes Elements 3 and 4 should be further evaluated
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B2.1.5 upper core plate alignment pins and B2.1.6 fuel pins.*	No
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling	Yes TLAA

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

B2. REACTOR VESSEL INTERNALS (PWR) - Westinghouse

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Thermal Aging and Neutron Irradiation Embrittlement on Item B2.1.2, upper support column constructed of CASS.	*Same as for the effect of Thermal Aging and Neutron Irradiation Embrittlement on Item B2.1.2, upper support column constructed of CASS.*	No
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B2.1.5 upper core plate alignment pins and B2.1.6 fuel pins.*	No
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B2.1.1, upper support plate, B2.1.4 upper core plate, and B2.1.7 hold-down spring.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B2.1.5 upper core plate alignment pins and B2.1.6 fuel pins.*	No

B3. Reactor Vessel Internals (PWR) - Combustion Engineering

B3.1 Upper Internals Assembly

B3.1.1 Upper Guide Structure Support Plate

B3.1.2 Fuel Alignment Plate

B3.1.3 Fuel Alignment Plate Guide Lugs

B3.1.4 Hold-Down Rings

B3.2 CEA Shroud Assemblies

B3.2.1 CEA Shrouds

B3.2.2 CEA Shrouds Bolts

B3.2.3 CEA Shrouds Extension Shaft Guides

B3.3 Core Support Barrel

B3.3.1 Core Support Barrel

B3.3.2 Core Support Barrel Upper Flange

B3.3.3 Core Support Barrel Alignment Keys

B3.4 Core Shroud Assembly

B3.4.1 Core Shroud Assembly

B3.4.2 Core Shroud Assembly Bolts

B3.4.3 Core Shroud Tie Rods

B3.5 Lower Internal Assembly

B3.5.1 Core Support Plate

B3.5.2 Fuel Alignment Pins

B3.5.3 Lower Support Structure Beam Assemblies

B3.5.4 Core Support Column

B3.5.5 Core Support Column Bolts

B3.5.6 Core Support Barrel Snubber Assemblies

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) inaccessible regions are difficult to inspect visually. Supplementary UT examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although stainless steel components in PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, potential for SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84–18), from the introduction of relatively high levels of dissolved oxygen during shutdown, or from aggressive chemistries that may develop in creviced regions. Cracking has occurred in SS baffle former bolts in a number of foreign plants (IN 98-11) and has now been observed in US plants. The mechanism of this particular cracking has not yet been resolved. SCC has also been observed in Ni alloy (Alloy X–750) control rod drive guide tube support pins (IN 82-29). Replacement components with a different heat treatment appear to be less susceptible to cracking.	
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT–3) is performed according to Category B–N–3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B3.1.1 upper guide structure support plate, B3.1.3 fuel alignment plate guide lugs., and B3.1.4 hold-down ring.*	No

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** There are no reports of stress relaxation producing damage in reactor vessel internals.	
Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	***(1) Scope of Program:*** The program includes inservice inspection (ISI) to detect cracking and/or failure, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** No practical preventative actions are possible. Stainless steels are susceptible to embrittlement under neutron irradiation. Fracture toughness will depend strongly on the fluence on a particular component. Components can be screened out if the maximum tensile loading on the component under ASME Code Level A, B, C, and D conditions is sufficiently low. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of neutron irradiation embrittlement on the intended function of the component by detection and sizing of cracks by inservice inspection (ISI). Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** Loss of fracture toughness is of consequence only if cracks exist. Cracking is expected to initiate at the surface and should be detectable by ISI except for some crevice regions. VT-3 may not be adequate to detect tight cracks. Also, creviced regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is	Yes Elements 3 and 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** No instances of internals degradation recorded have been definitely attributed to irradiation embrittlement.	
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Items B3.1.1 upper guide structure support plate, B3.1.3 fuel alignment plate guide lugs., and B3.1.4 hold-down ring.*	No
Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B3.3.1 core support barrel and B3.3.2 core support barrel upper flange.*	Yes Elements 3 and 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.*	Yes Element 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B3.3.1 core support barrel and B3.3.2 core support barrel upper flange.*	Yes Elements 3 and 4 should be further evaluated
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B3.2.2 CEA shroud bolts.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.*	Yes Element 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Items B3.1.1 upper guide structure support plate, B3.1.2 fuel alignment plate, and B3.1.3 fuel alignment plate guide lugs.*	Yes Element 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.	*Same as for the effect of Stress Corrosion Cracking on Item B3.2.2 CEA shroud bolts.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B3.3.1 core support barrel and B3.3.2 core support barrel upper flange.*	Yes Elements 3 and 4 should be further evaluated
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B3.2.2 CEA shroud bolts.*	Yes Elements 3 and 4 should be further evaluated

B4 Reactor Vessel Internals (PWR) - Babcock & Wilcox

B4.1 Plenum Cover and Plenum Cylinder

B4.2 CRA Guide Tube Assemblies

- B4.2.1 Tubes
- B4.2.2 Spacer Casting
- B4.2.3 Spider Casting
- B4.2.4 Bolts

B4.3 Upper Grid Assembly

- B4.3.1 Upper Grid Rib Section
- B4.3.2 Upper Grid Assembly Bolts
- B4.3.3 Plenum Rib Pads

B4.4 Core Support Assembly

- B4.4.1 Core Support Shield
- B4.4.2 Core Support Shield Flange
- B4.4.3 Core Support Shield to Core Barrel Bolts

B4.5 Vent Valve Assembly

B4.6 Core Barrel Assembly

- B4.6.1 Core Barrel
- B4.6.2 Core Barrel Bolts
- B4.6.3 Core Barrel to Thermal Shield Bolts

B4.7 Lower Grid Assembly (LGA)

- B4.7.1 Upper Grid
- B4.7.2 Fuel Guide Pads
- B4.7.3 Lower Grid

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) greatly reduces susceptibility to IASCC. However, introduction of oxygen can occur during shutdown and potential exists for the formation of more aggressive chemistry conditions by radiolysis in creviced regions or in low-flow stagnant regions. Also for sufficiently high fluence levels, IASCC can occur even in low oxygen environments. The AMP must rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on the intended function by detection and sizing of cracks by inservice inspection (ISI). Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** Degradation due to IASCC can not occur without crack initiation and growth. VT-3 may not be adequate to detect tight cracks. The inspection technique, including the reliability in detecting the features of interest (crack appearance and size) in assuring the integrity of the component, should be specified. For example, enhancement of the visual VT-1 examination to achieve a 1/2-mil (0.0005 in.) resolution, with the conditions (lighting and surface cleanness) for the ISI bounded by those used to demonstrate the resolution of the inspection technique. Creviced regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. As an alternate to enhanced inspection, perform a component-specific evaluation including a mechanical loading assessment to determine the maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the only cracking presently directly attributable to IASCC in PWRs occurred in SS fuel cladding used in early reactors, susceptibility to this degradation will increase as plant operating time and hence accumulated fluence levels increase. The role of IASCC in the more recent cracking that has occurred in SS baffle/former bolts in U.S. plants as well as foreign plants (IN 98-11) has not yet been universally agreed upon.	
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	**Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP.** ~~[illegible]~~ Applicant should address loss of ductility associated with void swelling.	**Yes TLAA**

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Determination of the susceptibility of CASS components to thermal aging embrittlement based on casting method, Mo content, and percent ferrite. For "potentially susceptible" components, based on the neutron fluence of the component, implement either a supplemental examination of the affected components as part of the applicant's 10-year inservice inspection (ISI) program during the license renewal term or a component-specific evaluation to determine the susceptibility to loss of fracture toughness.	***(1) Scope of Program:*** The program includes determination of the susceptibility of CASS components to thermal aging based on casting method, Mo content, and percent ferrite, and for "potentially susceptible" components, to account for the synergistic loss of fracture toughness due to neutron embrittlement and thermal aging embrittlement, implement either a supplemental examination of the affected components as part of a 10-year inservice inspection (ISI) program during the license renewal term or a component-specific evaluation to determine the susceptibility to loss of fracture toughness. ***(2) Preventive Actions:*** The program provides no guidance on methods to mitigate thermal aging or neutron embrittlement. ***(3) Parameters Monitored/ Inspected:*** The program specifics depend on the neutron fluence and ferrite content of the component. The criteria in EPRI TR-106092, with some modifications approved by the NRC staff, can be used to determine whether CASS components are potentially susceptibility to thermal aging embrittlement based on the casting method, Mo content, and ferrite content. For low-Mo content (0.5 wt.% max.) steels, only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement, all centrifugal-cast and static-cast steels with ≤20% ferrite are not susceptible. For high-Mo content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement, static-cast steels with ≤14% ferrite and centrifugal-cast steels with ≤20% ferrite are not susceptible. Ferrite content will be calculated by the Hull's equivalent factors or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). ***(4) Detection of Aging Effects:*** For all CASS components that have a neutron	No

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

B4. REACTOR VESSEL INTERNALS (PWR) - Babcock & Wilcox

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	***(1) Scope of Program:*** The program includes inservice inspection (ISI) to detect cracking and/or failure, and repair and/or replacement as needed to maintain the capability to perform the intended function. ***(2) Preventive Actions:*** No practical preventative actions are possible. Stainless steels are susceptible to embrittlement under neutron irradiation. Fracture toughness will depend strongly on the fluence on a particular component. Components can be screened out if the maximum tensile loading on the component under ASME Code Level A, B, C, and D conditions is sufficiently low. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of neutron irradiation embrittlement on the intended function of the component by detection and sizing of cracks by inservice inspection (ISI). Table IWB-2500, category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor internals. ***(4) Detection of Aging Effects:*** Loss of fracture toughness is of consequence only if cracks exist. Cracking is expected to initiate at the surface and should be detectable by ISI except for some crevice regions. VT-3 may not be adequate to detect tight cracks. Also, creviced regions are difficult to inspect visually and supplementary UT or other nondestructive examinations may be needed. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 is adequate for timely detection of cracks. ***(6) Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3520.	Yes Elements 3 and 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWB-3140. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** No instances of internals degradation recorded have been definitely attributed to irradiation embrittlement.	
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Wear on Item B4.2.1 CRA guide tubes.*	No
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B4.2.2 CRA guide tubes bolts.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B4.2.1-B4.2.3 upper grid assembly rib section, bolts, and plenum rib pads.*	Yes Elements 3 and 4 should be further evaluated
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as the effect of Wear on Item B4.2.1, CRA guide tubes*	No

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B4.2.1-B4.2.3 upper grid assembly rib section, bolts, and plenum rib pads.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Thermal Aging and Neutron Embrittlement on Items B4.2.1- B1.2.3 CRA guide tubes, spacer casting, and spider casting.	*Same as for the effect of Thermal Aging and Neutron Embrittlement on Items B4.2.1- B1.2.3 CRA guide tubes, spacer casting, and spider casting.*	No
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B4.2.1-B4.2.3 upper grid assembly rib section, bolts, and plenum rib pads.*	Yes Elements 3 and 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of the original licensing criteria or ASME Section III (edition specified in 10 CFR 50.55a), Subsection NG.	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Stress Relaxation on Item B4.2.2 CRA guide tubes bolts.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP. Applicant should address loss of ductility associated with void swelling.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B4.2.1-B4.2.3 upper grid assembly rib section, bolts, and plenum rib pads.*	Yes Elements 3 and 4 should be further evaluated
Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.	*Same as for the effect of Irradiation Assisted Stress Corrosion Cracking on Item B4.1, plenum cover and plenum cylinder.*	Yes Element 4 should be further evaluated
Plant specific aging management program. Based on EPRI TR-107521, estimates of void swelling vary from 14% for baffle-former assemblies over a 40-y plant life to less than 3% for the most highly irradiated sections of the internals at 60 y.	Plant specific aging management program is to be evaluated. The applicant must provide the basis for concluding that void swelling is not an issue for the component or must provide an AMP.	Yes TLAA
Visual inspection (VT-3) is performed according to Category B-N-3 of Subsection IWB, ASME Section XI.	*Same as for the effect of Neutron Irradiation Embrittlement on Items B4.2.1-B4.2.3 upper grid assembly rib section, bolts, and plenum rib pads.*	Yes Elements 3 and 4 should be further evaluated

C1. Reactor Coolant Pressure Boundary (Boiling Water Reactor)

C1.1 Piping & Fittings

C1.1.1 Main Steam

C1.1.2 Feedwater

C1.1.3 High Pressure Coolant Injection (HPCI) System

C1.1.4 Reactor Core Isolation Cooling (RCIC) System

C1.1.5 Recirculation

C1.1.6 Residual Heat Removal (RHR) System

C1.1.7 Low Pressure Coolant Injection (LPCI) System

C1.1.8 Low Pressure Core Spray (LPCS) System

C1.1.9 High Pressure Core Spray (HPCS) System

C1.1.10 Isolation Condenser

C1.1.11 Lines to Reactor Water Cleanup (RWC) and Standby Liquid Control (SLC) Systems

C1.1.12 Steam Line to HPCI and RCIC Pump Turbine

C1.2 Recirculation Pump

C1.2.1 Bowl / Casing

C1.2.2 Cover

C1.2.3 Seal Flange

C1.2.4 Closure Bolting

C1.3 Safety & Relief Valves

C1.3.1 Valve Body

C1.3.2 Bonnet

C1.3.3 Seal Flange

C1.3.4 Closure Bolting

C1.4 Isolation Condenser

C1.4.1 Tubing

C1.4.2 Tubesheet

C1.4.3 Channel Head

C1.4.4 Shell

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Program delineated in NUREG-0313, Rev. 2 and NRC Generic letter (GL) 88-01 and its Supplement 1, and inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Subsection IWB, Table IWB 2500-1, examination categories B-J for pressure retaining welds in piping and B-F for pressure retaining dissimilar metal welds, and testing category B-P for system leakage. BWRVIP guideline is under staff review. Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. Has the staff accepted the → BWRVIP document? If yes, then it should be referenced approp-riately.	***(1) Scope of Program:*** The program is focused on managing and implementing the counter measures to mitigate IGSCC and inservice inspection (ISI) to monitor IGSCC and its effects on the intended function of austenitic stainless steel (SS) piping 4 in. or larger in diameter, and reactor vessel attachments and appurtenances. NUREG-0313 and GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigating IGSCC in BWRs. ***(2) Preventive Actions:*** Mitigation of IGSCC is by selection of material considered resistant to sensitization and IGSCC, e.g., low-carbon grades of austenitic SSs and weld metal, with a maximum carbon of 0.035% and minimum 7.5% ferrite in weld metal, and by special processing such as solution heat treatment, heat sink welding, and induction heating or mechanical stress improvement (SI). Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. Also, hydrogen water chemistry and stringent control of conductivity is used to inhibit IGSCC. ***(3) Parameters Monitored/Inspected:*** Inspection and flaw evaluation are to be performed in accordance with referenced BWRVIP guideline, as approved by the NRC staff. ***(4) Detection of Aging Effects:*** Aging degradation of the piping can not occur without crack initiation and growth; extent and schedule of inspection as delineated in GL 88-01 and updated in BWRVIP-75 is adequate and will assure timely detection of cracks before the loss of intended function of austenitic SS piping and fittings. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with applicable approved BWRVIP guideline. ***(6) Acceptance Criteria:*** Any IGSCC degradation is evaluated in accordance with applicable approved BWRVIP guideline. ***(7) Corrective Actions:*** The corrective action proposed by the BWRVIP is under staff review. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** IGSCC has occurred in small- and large-diameter BWR piping made of austenitic SSs. Significant cracking has occurred in RHR system and reactor water cleanup system piping welds.	Yes, BWRVIP Guideline ← ?
Determination of the susceptibility of CASS piping to thermal aging embrittlement based on casting method, Mo content, and percent ferrite. For "potentially susceptible" piping, aging management is accomplished either through enhanced volumetric examination or plant/component-specific flaw tolerance evaluation. Additional inspection or evaluations are not required for "not susceptible" piping to demonstrate that the material has adequate fracture toughness. For pump casings and valve bodies,	***(1) Scope of Program:*** The program includes determination of the susceptibility of CASS components to thermal aging based on casting method, Mo content, and percent ferrite, and for potentially susceptible components aging management is accomplished either through volumetric examination or plant/component-specific flaw tolerance evaluation. ***(2) Preventive Actions:*** The program provides no guidance on methods to mitigate thermal aging. ***(3) Parameters Monitored/ Inspected:*** Based on the criteria in EPRI TR-106092, with some modifications, the susceptibility to thermal aging embrittlement of CASS piping is determined in terms of casting method, Mo content, and ferrite content. For low-Mo content (0.5 wt.% max.) steels, only static-cast steels	No

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

C1. REACTOR COOLANT PRESSURE BOUNDARY (Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
(continued from previous page) screening for susceptibility to thermal aging is not required. Also, the existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are considered adequate for all pump casings and valve bodies. ? ⇒ Pump casings and valve bodies are susceptible to thermal aging and they are within the scope of the license renewal. Therefore, they should be evaluated as part of aging management program.	*(continued from previous page)* with >20% ferrite are potentially susceptible to thermal embrittlement, all centrifugal-cast and static-cast steels with ≤20% ferrite are not susceptible. For high-Mo content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement, static-cast steels with ≤14% ferrite and centrifugal-cast steels with ≤20% ferrite are not susceptible. Ferrite content will be calculated by the Hull's equivalent factors or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). For pump casings and valve bodies, screening for susceptibility to thermal aging is not required. ***(4) Detection of Aging Effects:*** For "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. For "potentially susceptible" piping, because the base metal does not receive periodic inspection per ASME Section XI, volumetric examination should be performed on the base metal, with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Alternatively, a plant/component- specific flaw tolerance evaluation, using specific geometry and stress information, can be used to demonstrate that the thermally-embrittled material has adequate toughness. Current volumetric examination methods are inadequate for reliable detection of cracks in CASS components; the performance of the equipment and techniques when developed, should be demonstrated through the program consistent with the ASME Section XI, Appendix VIII. For all pump casings and valve bodies, the existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are considered adequate. For valve bodies less than NPS 4, the adequacy of inservice inspection according to ASME Section XI has been demonstrated by a NRC performed bounding fracture analysis. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 should provide timely detection of cracks. ***(6) Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. If aging management is accomplished through plant/component-specific flaw tolerance evaluation, e.g., for potentially susceptible piping, flaw evaluation for piping with <25% ferrite is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). Flaw evaluation for piping with >25% ferrite is performed on a case-by-case basis using fracture toughness data provided by the applicant. ***(7) Corrective Actions:*** Repair is in conformance with IWA-4000 and IWB-4000, and replacement according to IWA-7000 and IWB-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR	why not ?

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
C1.1.5, C1. 1.11	Piping & Fittings	Recirculation, Lines to RWC and SLC Systems	SS	288°C, Oxygenated Water	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
C1.1.6 thru C1. 1.10	Piping & Fittings	RHR, LPCI, LPCS, HPCS, IC	CS, SS	288°C Oxygenated Water or Steam	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
C1.2.1 thru C1.2.3	Recirculation Pump	Bowl/Casing, Cover, Seal Flange	CASS, SS	288°C, Oxygenated Water	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
C1.2.1, C1.2.2	Recirculation Pump	Bowl/Casing, Cover	CASS (SA351 CF-8 or CF-8M)	288°C, Oxygenated Water	Loss of Fracture Toughness	Thermal Aging Embrittle-ment	EPRI TR-106092. ASME Section XI, 1989 Edition.
C1.2.1	Recirculation Pump	Bowl/Casing	CASS, SS	288°C, Oxygenated Water	Crack Initiation and Growth	SCC, IGSCC	ASME Section XI, 1989 Edition. NUREG-0313, Rev. 2. NRC GL 88-01. NRC GL 88-01, S 1. BWRVIP-29. EPRI TR-103515.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as for the effect of Erosion/Corrosion on Item C1.1.1 main steam piping and fittings.	*Same as for the effect of Erosion/Corrosion on Item C1.1.1 main steam piping and fittings.*	Yes, Element 1 should be further evaluated
Same as for the effect of Thermal Aging Embrittlement on piping and fittings in various reactor coolant pressure boundary systems Items C1.1.5 - C1.1.11.	*Same as for the effect of Thermal Aging Embrittlement on piping and fittings in various reactor coolant pressure boundary systems Items C1.1.5 - C1.1.11.*	No
Guidelines of NUREG-0313, Rev. 2 and NRC Generic letter (GL) 88-01 and its Supplement 1; inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Subsection IWB, Table IWB 2500-1, examination categories B-M-1 for valve body welds and B-M-2 for valve body, and testing category B-P for system leakage. Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) and inservice inspection (ISI) to monitor the effects of SCC on intended function of the valves. NUREG-0313 and GL 88-01, respectively, describe the technical basis and staff guidance regarding the problem of IGSCC in BWRs. ***(2) Preventive Actions:*** Mitigation of IGSCC is by selection of material considered resistant to sensitization and IGSCC, e.g., low-carbon grades of cast SSs and weld metal, with a maximum carbon of 0.035% and minimum 7.5% ferrite. Also, hydrogen water chemistry and stringent control of conductivity is used to inhibit IGSCC. ~~However,~~ High-carbon grades of cast SS, e.g., CF-8 and CF-8M ~~may~~ ~~be~~ susceptible to SCC. The aging management program must therefore rely upon ISI in accordance with GL 88-01 to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on intended function of the valves by detection and sizing of cracks by ISI. For welds NPS 4 or larger, the inspection requirements follow those delineated in GL 88-01. Inspection requirements of Table IWB 2500-1, examination category B-M-2 specifies visual VT-3 examination of internal surfaces of the valve. Inspection requirements of testing category B-P conducted according to IWA-5000 specify visual VT-2 (IWA-5240) examination of all pressure retaining components during system leakage test (IWB-5221) and system hydrostatic test (IWB-5222). Also, coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. ***(4) Detection of Aging Effects:*** Degradation of the valves due to SCC can not occur without crack initiation and growth; extent and schedule of inspection as delineated in GL 88-01 will assure detection of cracks before the loss of the intended function of the valves. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with GL 88-01 should provide timely detection of cracks. All welds are inspected each inspection period from at least one valve in each group performing similar functions in the system. Visual examination is required only when the valve is disassembled for maintenance, repair, or volumetric examination, but at least once during the period. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test is conducted at or near the end of each inspection interval. ***(6) Acceptance Criteria:*** Any SCC degradation is	No are

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
C1.3.3, C1.3.4	Valves	Seal Flange, Closure Bolting	Flange: CS, SS Bolting: HSLAS	Air, Leaking Oxygenated Water and/or Steam at 288°C	Attrition	Wear	NUREG-1339. EPRI NP-5769. NRC GL 91-17. IEB 82-02. ASME Section XI, 1989 Edition.
C1.3.1 thru C1.3.3	Valves (Check, Control, Hand, Motor-Operated, and Relief Valves)	Valve Body, Bonnet, Seal Flange	CS, CASS, SS	288°C, Oxygenated Water	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
C1.3.4	Valves	Closure Bolting	HSLAS SA193 GrB7	Air, Leaking Oxygenated Water and/or Steam at 288°C	Loss of Preload	Stress Relaxation	NUREG-1339. EPRI NP-5769. NRC GL 91-17. IEB 82-02. ASME Section XI, 1989 Edition.
C1.3.4	Valves	Closure Bolting	HSLAS SA193 GrB7	Air, Leaking Oxygenated Water and/or Steam at 288°C	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
C1.4.1 thru C1.4.4	Isolation Condenser	Tubing, Tubesheet, Channel Head, Shell	Tubes: SS; Tubesheet: CS, SS; Channel Head: CS, SS; Shell: CS	Tube side: Steam; Shell side: demineralized water	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition. ASME OM S/G, Pt 2. NRC GL 89-13. Plant Technical Specifications.

C2. Reactor Coolant System and Connected Lines (Pressurized Water Reactor)

C2.1 Reactor Coolant System Piping & Fittings

C2.1.1 Cold–Leg

C2.1.2 Hot–Leg

C2.1.3 Surge Line

C2.1.4 Spray Line

C2.1.5 Small-Bore RCS Piping

C2.2 Connected Systems Piping & Fittings

C2.2.1 Residual Heat Removal (RHR) or Low–Pressure Injection System
(Decay Heat Removal (DHR)/ Shutdown System)

C2.2.2 Core Flood System (CFS)

C2.2.3 Chemical and Volume Control System or High-Pressure Injection System (Makeup & Letdown Functions)

C2.2.4 Sampling System

C2.2.5 Drains and Instrument Lines

C2.2.6 Nozzles and Safe Ends

C2.2.7 Small-Bore Piping in Connected Systems

C2.3 Reactor Coolant Pump

C2.3.1 Bowl / Casing

C2.3.2 Cover

C2.3.3 Closure Bolting

C2.4 Safety & Relief Valves

C2.4.1 Valve Body

C2.4.2 Bonnet

D1 Steam Generator (Recirculating)

D1.1 Pressure Boundary and Structural

D1.1.1 Top Head

D1.1.2 Steam Nozzle and Safe End

D1.1.3 Upper and Lower Shell

D1.1.4 Transition Cone

D1.1.5 Feedwater Nozzle and Safe End

D1.1.6 Feedwater Impingement Plate and Support

D1.1.7 Secondary Manways and Bolting

D1.1.8 Secondary Handholes and Bolting

D1.1.9 Instrument Nozzles

D1.1.10 Primary Manways and Bolting

D1.2 Tube Bundle

D1.2.1 Tubes

D1.2.2 Tube Support Plates

D1.2.3 Tube Support Lattice Bars (Combustion Engineering)

D1.2.4 Tube Plugs

D1.2.5 Tube Repair Sleeves

D1.3 Upper Assembly and Separators

D1.3.1 Feed Water Inlet Ring

D1.4 Piping and Fittings

D1.4.1 Main Steam

D1.4.2 Feedwater

D1.4.3 Auxiliary Feedwater

D1.5 Safety and Relief Valves

D1.5.1 Body

D1. Steam Generator (Recirculating)

System, Structures, and Components

The system, structures, and components included in this table consist of the recirculating-type steam generators, as found in Westinghouse and Combustion Engineering pressurized water reactors (PWRs), including all internal components, external primary and secondary water/steam nozzles and safe ends, and portions of main steam, feedwater, and auxiliary feedwater systems extending from the steam generator up to the first isolation valve outside of containment or to the first anchor point. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," the primary water side (tube side) of the steam generator is classified as Group A Quality Standards and secondary water side, including portions of main steam, feedwater, and auxiliary feedwater systems extending up to the first isolation valve outside of containment, is classified as Group B Quality Standard. The aging management program for the lines that penetrate the containment, and associated isolation valves, is reviewed in Table V C.

The valve internals are considered to be active components. They perform their intended functions with moving parts or with a change in configuration and are not subject to aging management review pursuant to 10 CFR 54.21(a)(1)(i).

System Interfaces

The systems that interface with the steam generators include the reactor coolant system and connected lines (Table IV C2), containment isolation components (Table V C), main steam system (Table VIII B1), feedwater system (Table VIII D1), steam generator blowdown system (Table VIII F), and auxiliary feedwater system (Table VIII G).

Fatigue related aging effect due to 300°C steam environment should be evaluated. Fatigue data in steam environment may not be readily available, within nuclear industry. Other process industry including fossil plants may have some data.

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

D1. STEAM GENERATOR (Recirculating)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.1.1, D1.1.2	Pressure Boundary and Structural	Top Head, Steam Nozzle & Safe End	Low-alloy Steel (LAS)	Up to 300°C Steam	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. GSI-190.
D1.1.2	Pressure Boundary and Structural	Steam Nozzle & Safe End	LAS	Up to 300°C Steam	Wall Thinning	Erosion/ Corrosion (E/C)	NUREG-1344. EPRI NSAC-202L-R2. NRC IN 93-21. EPRI TR-102134. *Operating Experience* NRC BL 87-01. NRC GL 89-08. NRC IN 89-53. NRC IN 91-18. NRC IN 91-18 S1. NRC IN 91-28. NRC IN 92-35. NRC IN 95-11. NRC IN 97-84.

GSI 190 indicates that the effect of the environment needs to be addressed in fatigue evaluations. In this case the environment is 300°C steam. What is the fatigue life, or environmental effect, for steam? Should we state that the environmental effect for steam should be used? Can the environmental effect for high T, P, water be used? Is steam more aggressive

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a) or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Program delineated in NUREG-1344 for single phase lines and implemented through NRC Generic Letter 89-08; CHECWORKS Code; EPRI guidelines of NSAC-202L-R2 for effective erosion/corrosion program; and water chemistry program based on EPRI guidelines for secondary water chemistry (EPRI TR-102134).	***(1) Scope of Program:*** The AMP includes NUMARC program delineated in Appendix A of NUREG-1344 and implemented through NRC Generic Letter (GL) 89-08; CHECWORKS computer Code; and EPRI guidelines of NSAC-202L-R2. The program includes the following recommendations: (a) conduct appropriate analysis and limited baseline inspection, (b) determine the extent of thinning and repair/replace components, and (c) perform follow-up inspections to confirm or quantify and take longer term corrective actions. Technical aspects of the CHECWORKS Code, including the parameters and inputs, are acceptable. However, the EPRI guidance document NSAC-202L-R2 (April 1999) is too general to ensure applicant's flow-accelerated corrosion program will be effective in managing aging in safety-related systems. ***(2) Preventive Actions:*** The rate of E/C is affected by piping material, geometry and hydrodynamic conditions, and operating conditions such as temperature, pH, and dissolved oxygen content. Mitigation is by selecting material considered resistant to E/C, adjusting water chemistry and operating conditions, and improving hydrodynamic conditions through design modifications. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of E/C on the intended function of piping by measuring wall thickness by nondestructive examination and performing analytical evaluations. The inspection program delineated in NUREG-1344 requires ultrasonic or radiographic testing of 10 most susceptible locations and 5 additional locations based on unique operating conditions or special considerations. For each location outside the acceptance guidelines, the inspection sample is expanded based on engineering judgment. Analytical models such as those incorporated into the CHECWORKS code are used to predict E/C in piping systems based on specific plant data including material and hydrodynamic and operating conditions. The inspection data is used to calibrate and benchmark the models and code. ***(4) Detection of Aging Effects:*** Aging degradation of piping and fittings occurs by wall thinning; extent and schedule of inspection assure detection of wall thinning before the loss of intended function of the piping. ***(5) Monitoring and Trending:*** Inspection schedule of NUREG-1344 and EPRI guidelines should provide for timely detection of leakage. Inspections and analytical evaluations are performed during plant outage. If analysis shows unacceptable conditions, inspection of initial sample is performed within 6 months. ***(6) Acceptance Criteria:*** Inspection results are used to calculate number of refueling or operating cycles remaining before the component reaches Code minimum allowable wall thickness. If calculations indicate that an area will	Yes, Element 1 should be further evaluated

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.1.3 thru D1.1.6	Pressure Boundary and Structural	Upper & Lower Shell, Transition Cone, FW Nozzle & Safe End, FW Impingement Plate Support	Carbon steel (CS), LAS	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. GSI-190.
D1.1.3, D1.1.4	Pressure Boundary and Structural	Upper & Lower Shell, Transition Cone	CS, LAS	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition. EPRI TR-102134. *Operating Experience* NRC IN 82-37. NRC IN 85-65. NRC IN 90-04.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) reach Code minimum (plus 10% margin), the component must be repaired or replaced. However, NRC staff has identified the problems in implementing E/C program that pertain to weakness or errors in (a) using predictive models, (b) calculating minimum wall thickness acceptance criteria, (c) analyzing the results of UT examinations, and (d) assessment of E/C program activities (NRC Information Notice IN 93-21). ***(7) Corrective Actions:*** Prior to service, repair or replace to meet the requirements of NUREG-1344. Follow-up inspections are performed to confirm or quantify thinning and take longer term corrective actions such as adjustment of chemistry and operating parameters, or selection of materials resistant to E/C. However, NRC staff has identified weakness or errors in (a) dispositioning components after reviewing the results of the inspection analysis, and (b) repairing or replacing components that failed to meet the acceptance criteria (IN 93-21). ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC Bulletin No. 87-01, INs 81-28, 92-35, 95-11), and in two-phase piping in extraction steam lines (INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (INs 89-53, 91-18, 93-21, 97-84). The AMP outlined in NUREG-1344 and EPRI report and implemented through GL 89-08 has provided effective means of ensuring the structural integrity of all high-energy carbon steel systems.	
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a) or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
The program includes preventive measures to mitigate crevice corrosion by recommendations on secondary water chemistry of EPRI TR-102134 and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a) Table IWC 2500-1, examination category C-A for pressure retaining welds in pressure vessels, and examination category C-H for pressure retaining Class 2 components.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and inservice inspection (ISI) to monitor the effects of corrosion on the intended function of the steam generator shell. ***(2) Preventive Actions:*** Stringent control of secondary water chemistry in accordance with the guidance of EPRI TR-102134, frequent monitoring, and timely corrective action when specified impurity levels are exceeded, prevent or mitigate corrosion. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by detection and sizing of flaws in pressure retaining welds and by detection of coolant leakage by inservice inspection (ISI). Inspection requirements of Table IWC 2500-1, examination	Yes Element 4 should be further evaluated

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.1.5	Upper Assembly and Separators	FW Nozzle & Safe End	LAS	Up to 225°C Secondary-side Water Chemistry	Wall Thinning	Erosion/ Corrosion (E/C)	*Same as the effect of Erosion/ Corrosion on Item D1.1.2 Steam Nozzle and Safe End*
D1.1.6	Upper Assembly and Separators	Feedwater Impingement Plate Support	CS	Up to 300°C Secondary-side Water Chemistry	Loss of section thickness	Erosion	Plant Technical Specifications

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Do pitting corrosion and crevice corrosion appear only at the welds? Is inspection of only the welds adequate? Shouldn't we inspect for crevice corrosion in locations where crevices exist? for pitting where pitting is expected? The reviewer's question is, how a program that addresses welds associated with the component will find effects of pitting and corrosion likely to occur away from the weld?	*(continued from previous page)* category C-A specify volumetric examination, extending 1/2 in. each side, of all circumferential and tubesheet-to-shell welds, and visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 2 components. Requirements for training and qualification of personnel and performance demonstration for procedures and equipment is in conformance with Appendix VII and VIII of ASME Section XI, or any other formal program approved by the NRC. ***(4) Detection of Aging Effects:*** The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, based on NRC Information notice 90-04 where general corrosion pitting of the shell exists, the program requirements may not be sufficient to differentiate isolated cracks from inherent geometric conditions, and additional inspection procedures may be required. ***(5) Monitoring and Trending:*** Inspection schedule of ASME Section XI should provide for timely detection of leakage. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. ***(6) Acceptance Criteria:*** Any defect detected is compared with the requirements of Section XI, IWC 3510. Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3410 and IWC-3516. ***(7) Corrective Actions:*** Welds containing flaws that exceed the maximum permissible size must be repaired. Repair and replacement are in conformance with IWA-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls, in conjunction with NRC oversight, are implemented in accordance with the requirements of Appendix B of 10 CFR 50. These requirements, in conjunction with enhanced UT techniques, should continue to ensure the timely detection and correction of virtually all forms of this type of degradation but cannot be depended upon to prevent further degradation. ***(10) Operating Experience:*** This AMP has resulted in the timely detection and correction of corrosion in several steam generators in the US. (NRC Information Notices 82-37 & 85-65).	
Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End	*Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End*	No
Plant-specific aging management program	Plant-specific aging management program will be evaluated	Yes no AMP

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.1.7, D1.1.8	Pressure Boundary and Structural	Secondary Manway & Bolting, Secondary Handhold & Bolting	CS, LAS	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Attrition	Wear	NUREG-1339. EPRI NP-5769. NRC GL 91-17. ASME Section XI, 1989 Edition. *Operating Experience* IEB 82-02.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) needed to meet the requirements of IWB-3142 and IWA-5250. The leakage source and areas of wear are located. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** To date, the present AMP has been effective in ensuring the timely detection and correction of wear degradation in steam generator manway and handhold.	
Implementation of NRC Generic Letter 88-05, and inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Subsection IWC, Table IWB 2500-1, testing category B-P.	***(1) Scope of Program:*** The staff guidance of Generic Letter (GL) 88-05 provides assurances that a program has been implemented consisting of systematic measures to ensure that the effects of corrosion caused by leaking coolant containing boric acid does not lead to degradation of the assurance that the reactor coolant pressure boundary will have a extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. The program includes (a) determination of principal location, (b) examinations requirements and procedures for locating small leaks, and (c) engineering evaluations and corrective actions. ***(2) Preventive Actions:*** Minimizing reactor coolant leakage by frequent monitoring of the locations where potential leakage could occur and repairing the leaky components as soon as possible, prevent or mitigate boric acid corrosion. ***(3) Parameters Monitored/Inspected:*** The AMP detects coolant leakage by inservice inspection (ISI). Inspection requirements of ASME Section XI, Table IWB 2500-1, testing category B-P specifies visual inspection of all Class 1 pressure-retaining components during system leakage and hydrostatic tests. ***(4) Detection of Aging Effects:*** Aging degradation of the component can not occur without leakage of coolant containing boric acid; extent and schedule of inspection assure detection of leakage before the loss of intended function of the component. ***(5) Monitoring and Trending:*** Inspection schedule of ASME Section XI should provide for timely detection of leakage. System leakage test is conducted at ≈40-month intervals. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWB-3100 and acceptance standards of NRC Generic Letter 88-05. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of NRC Generic Letter 88-05. The leakage source and areas of general corrosion are located. Components with local areas of corrosion that reduces the wall thickness by more than 10% require analytical evaluation to demonstrate acceptability. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:***	No Something is missing

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1. 1.10	Pressure Boundary and Structural	Primary Manway Bolting	LAS	Air, Leaking Chemically Treated Borated Water and/or Steam at temperatures up to 340°C	Crack Initiation and Growth	Stress Corrosion Cracking (SCC)	NUREG-1339. EPRI NP-5769. NRC GL 91-17. IEB 82-02. ASME Section XI, 1989 Edition.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) Boric acid wastage observed in nuclear power plants may be classified into two distinct types: (a) corrosion that increases the rate of leakage, e.g., corrosion of closure bolting or fasteners in reactor coolant pressure boundary, and (b) corrosion that occurs some distance from the source of leakage. Some recent incidents of boric acid wastage (IN 86-108 S3) at Calvert Cliffs Unit 1 (Feb. 1994) and Three Mile Island Unit 1 (March 1994) indicate that, although implementation of GL 88-05 ensures timely detection of leakage, there may still be a lack of awareness of the conditions that can lead to boric acid wastage.	
Recommendations for a comprehensive bolting integrity program delineated in NUREG–1339 on resolution of Generic Safety Issue 29 as described in NRC Generic Letter 91-17; additional details on bolting integrity outlined in EPRI NP-5769; and inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Subsection IWB, Table IWB 2500-1, examination categories B-G-1 and B-G-2 for pressure retaining bolting and category B-P for system leakage. Limits on operational leakage specified by Plant Technical Specifications.	***(1) Scope of Program:*** NRC Generic Letter (GL) 91-17 suggests an approach to implement a plant-specific comprehensive bolting integrity programs to ensure bolting reliability. The NRC staff recommendations and guidelines for a comprehensive bolting integrity program are delineated in NUREG-1339, and the industry's technical basis for the program is outlined in EPRI NP-5769. ***(2) Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants in accordance with guidelines of EPRI NP-5769 and additional requirements of NUREG 1339, prevent or mitigate degradation and failure of all safety-related closure bolting. ***(3) Parameter Monitored/ Inspected:*** The AMP monitors the effects of aging degradation on the intended function of closure bolting by detection of coolant leakage, and by detection and sizing of cracks by inservice inspection (ISI). Inspection requirements of ASME Section XI, Table IWB 2500-1, examination category B-G-1 for bolting >2 inches in diameter specify volumetric examination of studs and bolts from top of nut to bottom of the flange hole, and visual VT-I examination of surfaces of nuts, washers, bushings, and flanges, including a 1-inch annular surface of flange surrounding each stud. Examination category B-G-2 for bolting <2 inches in diameter specifics only visual VT-1 examination of surfaces of bolts, studs, and nuts.. However, most failures have occurred in fasteners 2 in. or smaller, and, based on IE Bulletin 82-02, enhanced inspection and improved techniques are recommended. Requirements for training and qualification of personnel and performance demonstration for procedures and equipment is in conformance with Appendices VII and VIII of ASME Section XI, and additional requirements of EPRI NP-5769. Inspection requirements of ASME Section XI testing category B-P specify visual VT-2 (IWA-5240) examination of all pressure retaining components during system leakage and hydrostatic testing. ***(4) Detection of Aging Effects:*** Degradation of the closure bolting can not occur without crack initiation. Also, loss of prestress or attrition of the closure bolting would result in leakage. The extent and schedule of inspection assure detection of aging degradation before the loss of intended function of closure bolting. ***(5) Monitoring and Trending:*** Inspection schedule of ASME Section XI is effective and adequate for timely detection of cracks and leakage. Inspection schedule in	No

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
D1.2.1	Tube Bundle	Steam Generator Tubes and Sleeves	Alloy 600	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Crack Initiation and Growth	PWSCC	Plant Technical Specifications, Reg. Guide 1.83. Reg. Guide 1.121. NRC GL 95-05. NRC IN 97-26. NRC IN 97-88. EPRI TR-105714, EPRI document "PWR Steam Generator Examination Guidelines: Rev. 5" NEI 97-06

not consistent

Sleeves are on the primary side - Mechanism is PWSCC must have primary side borated water

It seems we need two more sections for PWSCC: 1) tubesheet roll transition cracking and 2) PWSCC at dented tubes in tube support plate location.

Possibly these could be added and discussed under D.1.2.1 above.

Top of Tube Sheet, sludge pile, cracking has not been addressed - this would be due to SCC or crevice corrosion cracking

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) accordance with IWB-2400 requires inspection of all bolts, studs, nuts, bushing, and flange surfaces every 10 y. System leakage test is conducted at each refueling outage. ***(6) Acceptance Criteria:*** Any cracks in closure bolting are evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3515 and IWB-3517. Any relevant conditions that may be detected are compared with the acceptance standards of IWB-3522. ***(7) Corrective Actions:*** Repair and replacement is in conformance with IWA-4000 and recommendations and guidelines of EPRI NP-5769. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Significant number of incidents have been reported on bolts and nuts that have failed or become degraded because of boric acid wastage or SCC. Examples of affected fasteners include (a) steam generator and pressurizer manway closures, (b) valve bonnets and pump flange connections on lines 6 in. or greater, and (c) control rod drive and pressurizer heater connections. The present AMP has provided effective means of ensuring bolting reliability.	
Inservice inspection in conformance with Plant Technical Specifications and NRC Regulatory Guide (RG) 1.83 ("Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." Plugging or repair of defective tubes is governed by NRC Regulatory Guide 1.121 ("Bases for Plugging Degraded PWR Steam Generator Tubes"), but defects at the tube sheet may be shown to satisfy the 1.121 requirements using the P*, F*, or L* criterion. Alternative criteria applicable to cracking at the tube support plates in Westinghouse-designed steam generators under certain circumstances are provided in NRC Generic Letter (GL) 95-05 ("Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking"). Specific guidance on the inservice inspection of tubes is also provided in the EPRI document "PWR Steam Generator Examination Guidelines: Revision 5" and NEI 97-06. Supplemental inspection requirements and plugging criteria may be contained in plant-specific Technical Specifications.	***(1) Scope of Program:*** The program deals with the effects of SCC of the steam generator tubes on the integrity of the pressure boundary. Inservice inspection in accordance with Plant Technical Specifications and RG 1.83 deal with the detection of flaws, and RG 1.121 and NRC GL 95-05 describe the basis for determining when flawed tubes must be plugged or repaired. ***(2) Preventive Actions:*** Primary water chemistry guidelines given in EPRI TR-105714 provide guidance on the prevention of PWSCC. ***(3) Parameters Monitored/Inspected:*** The inspection activity in the program monitors flaw size and depth, or, alternatively, remaining sound wall thickness. ***(4) Detection of Aging Effects:*** The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the tubes. Problems with tube inspection (IN 97-88), e.g., failures to detect some flaws, uncertainties in flaw sizing, inaccuracies in flaw locations, and inability to detect some cracks at locations with dents are addressed by current inspection guidelines given in the EPRI document "PWR Steam Generator Examination Guidelines: Revision 5" and NEI 97-06. ***(5) Monitoring and Trending:*** Required inspection intervals (typically ≈18 months or each refueling or maintenance/repair outage) provide for timely detection of SCC. ***(6) Acceptance Criteria:*** Any cracking detected is compared with the requirements of the Plant Technical Specifications, RG 1.121, and GL 95-05. ***(7) Corrective Actions:*** Tubes containing flaws that exceed the maximum permissible size must be plugged or repaired. ***(8 & 9)***	No, provided Plant Technical Specifications conform to EPRI inspection guidelines and NEI 97-06 and are adhered to.

GL 95-05 applies to outside diameter SCC — I think here we're discussing PWSCC so the info. probably does not belong here

delete? this applies to ODSCC

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.2.1	Tube Bundle	Steam Generator Tubes	Alloy 600	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Crack Initiation and Growth	Outer Diameter Stress Corrosion Cracking (ODSCC)	Plant Technical Specifications. Reg. Guide 1.83. Reg. Guide 1.121. NRC GL 95-05, EPRI document "PWR Steam Generator Examination Guidelines: Rev. 5", NEI 97-06

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Inservice inspection in conformance with Plant Technical Specifications and NRC Regulatory Guide 1.83 ("Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes". Correlations for estimating plug life contained in Westinghouse reports WCAP-12244 and WCAP 12245. Specific guidance on the inservice inspection of plugs is provided in the EPRI document "PWR Steam Generator Examination Guidelines: Revision 5" and NEI 97-06. Supplemental inspection requirements may be contained in plant-specific Technical Specifications.	***(1) Scope of Program:*** The program deals with the periodic inspection of steam generator tube plugs. ***(2) Preventive Actions:*** Guidance on primary water chemistry provided in EPRI TR-102134 can significantly reduce PWSCC. The program also recommends that certain susceptible heats be avoided. ***(3) Parameters Monitored/ Inspected:*** The inspection activity in the program monitors flaw size and depth. ***(4) Detection of Aging Effects:*** The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the ~~tubes~~. Past problems with failure to detect flaws in plugs have led to leaking or failed plugs in several plants ((BL 89-01; 89-01, S. 1; 89-01, S. 2; IN 89-33, 94-87). However, improved detection procedures are provided in the EPRI document "PWR Steam Generator Examination Guidelines: Revision 5" and NEI 97-06. ***(5) Monitoring and Trending:*** Required inspection intervals (typically ≈18 months or each refueling or maintenance/repair outage) are intended to provide for timely detection of SCC. However, note item (4) immediately above ***(6) Acceptance Criteria:*** Any cracking detected requires replacement. Plug lives can be estimated using procedures in WCAP-12244 and 12245 and compared with the limits given in those reports. ***(7) Corrective Actions:*** Tube plugs containing flaws or having insufficient estimated lives must be replaced. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls, in conjunction with NRC oversight, are implemented in accordance with the requirements of Appendix B of 10 CFR 50. This should ensure the timely detection and correction of cracking. ***(10) Operating Experience:*** Problems appear to have been related to susceptible heats of material and improper heat treatment. However, any Alloy 600 mechanical plugs remaining in service must be considered susceptible (BL 89-01; 89-01, S 1; 89-01, S 2; IN 89-33, 94-87).	No, provided Plant Technical Specifi-cations conform to EPRI inspection guidelines and NEI 97-06 and are adhered to.
Inservice inspection in conformance with Plant Technical Specifications and NRC Regulatory Guide 1.83 ("Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes". Specific guidance on the inservice inspection of plugs is provided in the EPRI document "PWR Steam Generator Examination Guidelines: Revision 5" and NEI 97-06. Supplemental inspection requirements may be contained in plant-specific Technical Specifications.	***(1) Scope of Program:*** The program deals with the periodic inspection of steam generator tube plugs. ***(2) Preventive Actions:*** Guidance on primary water chemistry provided in EPRI TR-102134 can significantly reduce PWSCC. The program also recommends that certain susceptible heats be avoided. ***(3) Parameters Monitored/ Inspected:*** The inspection activity in the program monitors flaw size and depth. ***(4) Detection of Aging Effects:*** The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the ~~tubes~~. ***(5) Monitoring and Trending:*** Required inspection intervals (typically ≈18 months or each refueling or maintenance/repair outage) appears to provide for timely detection of SCC, and no leakage due to failed plugs has been reported. ***(6) Acceptance Criteria:*** Any cracking detected is	No, provided Plant Technical Specifi-cations conform to EPRI inspection guidelines and NEI 97-06 and are adhered to.

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.2..5	Tube Bundle	Tubes in the Region of Repair Sleeves	Alloy 600	Chemically Treated Borated Water at temperatures up to 340°C and 15.5 MPa	Crack Initiation and Growth	PWSCC	Plant Technical Specifications; NRC Reg. Guide 1.83; NRC IN 94-05; EPRI document "PWR Steam Generator Examination Guidelines: Rev. 5"; NEI 97-06
D1.3.1	Upper Assembly and Separators	Feedwater Inlet Ring and Supports	CS	Up to 300°C Secondary-side Water Chemistry at 5.3-7.2 MPa	Loss of Material	Erosion/ corrosion	ASME Section XI, 1989 Edition.; NRC IN 91-19; NRC LER 50-362/90-05-01; Combustion Engineering Info-bulletin 90-04

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) forms of degradation. ***(6) Acceptance Criteria:*** Any defect detected is compared with the requirements of the Plant Technical Specifications and with the recommendations of Combustion Engineering Info-bulletin 90-04. These requirements should ensure structural integrity. ***(7) Corrective Actions:*** Excessively degraded components must be repaired or replaced ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls, in conjunction with NRC oversight, are implemented in accordance with the requirements of Appendix B of 10 CFR 50. These requirements should continue to ensure the timely detection and correction of all forms of degradation. ***(10) Operating Experience:*** This form of degradation has been detected only in certain Combustion Engineering System 80 steam generators, where it has been successfully dealt with (NRC Information Notice I91-19; NRC LER 50-362/90-05-01).	
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a), ANSI B31.1, or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed. see previous comment related to fatigue life in steam	Yes TLAA
Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End	*Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End*	No
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a), Subsection NB, or ANSI B31.1, or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End	*Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End*	No
Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End	*Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End*	No

IV REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

D1. STEAM GENERATOR (Recirculating)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D1.4.1	Piping and Fittings	Main Steam	CS	Up to 300°C Steam	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition
D1.4.2, D1.4.3	Piping and Fittings	Feedwater, Auxiliary Feedwater	CS	Up to 300°C Secondary-side Water Chemistry	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition
D1.5.1	Safety and Relief Valves	Body	CS	Up to 300°C Steam or Secondary-side Water Chemistry	Wall Thinning	E/C	*Same as the effect of Erosion/Corrosion on Item D1.1.2 Steam Nozzle and Safe End*

how about the SG pressure vessel itself?
hot cracking in the transition cone area
some years ago

D2. Steam Generator (Once-Through)

D2.1 Pressure Boundary and Structural

- D2.1.1 Upper & Lower Heads
- D2.1.2 Tube Sheets
- D2.1.3 Primary Nozzles & Safe Ends
- D2.1.4 Shell
- D2.1.5 Feed Water and Auxiliary Feed Water Nozzles & Safe Ends
- D2.1.6 Steam Nozzles & Safe Ends
- D2.1.7 Instrument & Drain Nozzles
- D2.1.8 Primary Manways & Bolting
- D2.1.9 Secondary Manways Handholes & Bolting

D2.2 Tube Bundle

- D2.2.1 Tubes

D2.3 Piping and Fittings

- D1.4.1 Main Steam
- D1.4.2 Feedwater
- D1.4.3 Auxiliary Feedwater

D2.4 Safety and Relief Valves

- D1.5.1 Body

D2. Steam Generator (Once-Through)

D2.1 Pressure Boundary and Structural

D2.1.1 Upper & Lower Heads

D2.1.2 Tube Sheets

D2.1.3 Primary Nozzles & Safe Ends

D2.1.4 Shell

D2.1.5 Feed Water and Auxiliary Feed Water Nozzles & Safe Ends

D2.1.6 Steam Nozzles & Safe Ends

D2.1.7 Instrument & Drain Nozzles

D2.1.8 Primary Manways & Bolting

D2.1.9 Secondary Manways Handholes & Bolting

D2.2 Tube Bundle

D2.2.1 Tubes

D2.3 Piping and Fittings

D1.4.1 Main Steam

D1.4.2 Feedwater

D1.4.3 Auxiliary Feedwater

D2.4 Safety and Relief Valves

D1.5.1 Body

Some of the comments provided for D1, Steam Generator (Recirculating) should be reviewed for D2, Steam Generator (Once-Through).

Comments provided for D1.1.1 and D1.1.2 apply to D.2.1.1. Comment provided for D1.2.1 apply to D2.2.1

CHAPTER V

(12/06/99)

ENGINEERED SAFETY FEATURES

Major Plant Sections

A. Containment Spray System

B. Standby Gas Treatment System (Boiling Water Reactor)

C. Containment Isolation Components

D1. Emergency Core Cooling System (Pressurized Water Reactor)

D2. Emergency Core Cooling System (Boiling Water Reactor)

E. Fan Cooler System

A Containment Spray System

A.1 Containment Spray System

A.1.1 Piping and Fittings up to Isolation Valve

A.1.2 Flow Orifice/Elements

A.1.3 Temperature Elements/Indicators

A.1.4 Bolting

A.1.5 Eductors

A.2 Header and Spray Nozzles System

A.2.1 Piping and Fittings

A.2.2 Flow Orifice

A.2.3 Headers

A.2.4 Spray Nozzles

A.3 Chemical Addition System

A.3.1 Piping and Fittings

A.3.2 Storage Tank

A.4 Pumps

A.4.1 Bowl/Casing

A.4.2 Bolting

A.5 Valves (Hand, Control, Check, Motor-Operated) (in Containment Spray System)

A.5.1 Body and Bonnet

A.5.2 Bolting

A.6 Valves (Hand, Control) (in Header and Spray Nozzle System)

A.6.1 Body and Bonnet

A.6.2 Bolting

A.7 Containment Spray Heat Exchanger

A.7.1 Bonnet/Cover

A.7.2 Tubing

A.7.3 Shell

A.7.4 Case/Cover

A.7.5 Bolting

V ENGINEERED SAFETY FEATURES

A. CONTAINMENT SPRAY SYSTEM (Pressurized Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
A.1.1 thru A.1.3	Containment Spray System	Piping and Fittings up to Isolation Valve, Flow Orifice/ Elements, Temperature Elements/ Indicators	Stainless Steel (SS)	Chemically Treated Borated Water at Maximum Design Temperature of ≈205°C	Local Loss of Material are any areas of wear of greater importance than other areas? which region is more imp.	Pitting and Crevice Corrosion	ASME Section XI, 1989 Edition. NRC IN 84-18. Plant Technical Specifications. EPRI TR-105714.

C-H

Do all the components listed in the region of interest column experience loss of material @ the same rate & are they managed by the same programs?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Inservice inspection is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components. Water chemistry program for minimizing impurities by monitoring and maintaining water chemistry conditions based on guidelines of EPRI TR-105714 for primary water chemistry and plant technical specifications for refueling water storage tank water chemistry.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and inservice inspection (ISI) to monitor the effects of corrosion on the intended function of containment spray system components. ***(2) Preventive Actions:*** Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential for pitting and crevice corrosion. However, inadvertent introduction of contaminants into the coolant system can occur, e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by control of system water chemistry and by detection of coolant leakage by inservice inspection (ISI). Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 2 components required to operate or support the safety function according to Table IWC 2500-1 category C-H. ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516 for Class 2 components. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repairs are in conformance with IWA-4000 and replacement according to IWA-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR 50 and will continue to be adequate	Yes, Element 4 should be further evaluated How is the sample determined is a standard formula used for all systems or is the sample size done system by system

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) for the period of license renewal. ***(10) Operating Experience:*** Corrosion related degradation has not been reported for containment spray system components, but cracking has occurred in safety-related SS piping systems and portions of systems which contain oxygenated, stagnant, or essentially stagnant borated water.	
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-F-1 for pressure retaining welds in Class 2 stainless steel piping. Water chemistry program for minimizing impurities by monitoring and maintaining water chemistry conditions based on guidelines of EPRI TR-105714 for primary water chemistry and plant technical specifications for refueling water storage tank water chemistry.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of containment spray system components. ***(2) Preventive Actions:*** Selection of material in compliance with the guidelines of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential of SCC. However, inadvertent introduction of contaminants into the coolant system can occur, e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on the intended function of the piping by control of system water chemistry and by detection and sizing of cracks by ISI. Inspection requirements of IWC 2500-1 category C-F-1, specify for circumferential and longitudinal welds in each pipe or branch run NPS 4 or larger, volumetric and surface examination of ID region, and surface examination of OD surface. Surface examination is conducted for circumferential and longitudinal welds in each pipe or branch run less than NPS 4. Requirements for training and qualification of personnel and performance demonstration for procedures and equipment are in conformance with Appendices VII and VIII of ASME Section XI, or any other formal program approved by the NRC. ***(4) Detection of Aging Effects:*** Degradation of piping and fittings due to SCC can not occur without crack initiation; inspection schedule assures detection of cracks before the loss of intended function of the piping. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWC-2400 should provide timely detection of cracks. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. ***(6) Acceptance Criteria:*** Any SCC degradation is evaluated in accordance with IWC-3100 by comparing ISI results with the acceptance standards of IWC-3400 and IWC-3514. Supplementary surface examination may be performed on interior and/or exterior surfaces when flaws are detected in volumetric examination. ***(7) Corrective Actions:*** Repairs are in conformance with IWA-4000, replacement according to IWA-7000, and reexamination in accordance	No (handwritten: should → Is this true 100% of the time?)

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) in conformance with Appendices VII and VIII of ASME Section XI, or any other formal program approved by the NRC. ***(4) Detection of Aging Effects:*** Degradation of the piping due to SCC can not occur without crack initiation. The extent of inspection required by ASME Section XI is considered adequate to detect cracking of susceptible SS components and cladding in the weld regions. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWC-2400 should provides timely detection of cracks. ***(6) Acceptance Criteria:*** Any SCC degradation is evaluated in accordance with IWC-3100 by comparing ISI results with the acceptance standards of IWC-3400. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWC-3133, and reexamination in accordance with requirements of IWA-2200. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** No significant cracking has been reported for chemical addition lines in PWRs.	
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) and inservice inspection (ISI) to monitor the effects of SCC on the storage tank. ***(2) Preventive Actions:*** Selection of material in compliance with the guidelines of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of SCC by detection of leakage. Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage test and system hydrostatic test of all pressure retaining Class 2 components required to operate or support the safety function, according to Table IWC 2500-1 category C-H. ***(4) Detection of Aging Effects:*** Degradation of the component due to SCC can not occur without leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any	Yes, Element 4 should be further evaluated How is sample size determined?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516. Any evidence of aging effects or unacceptable results should be evaluated. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** No significant cracking has been reported for chemical addition storage tanks in PWRs.	
Inservice inspection is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components; and based on the testing requirements of 10 CFR 50.55a for ASME Code Class 2 pumps, and additional NRC staff guidelines of NRC Generic Letter 89-04, inservice testing performed in accordance with ASME Subsection IWP (or Operation and Maintenance Code Subsection ISTB) for pumps, or other approved program in the plant specifications. Water chemistry program based on EPRI guidelines of TR-105714 for minimizing impurities by monitoring and maintaining primary water chemistry.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and combination of inservice inspection (ISI) and inservice testing (IST) to monitor the effects of corrosion on the intended function of containment spray system components. ***(2) Preventive Actions:*** Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential for pitting and crevice corrosion. However, inadvertent introduction of contaminants into the coolant system can occur, e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by control of water chemistry and by ISI to detect coolant leakage and IST to evaluate component performance. Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 2 components required to operate or support the safety function according to Table IWC 2500-1 category C-H. Based on the requirements of 10 CFR 50.55a for ASME Code Class 2 pumps and additional guidelines of NRC Generic Letter (GL) 89-04, IST is performed in accordance with ASME Subsection IWP (or OM Code Subsection ISTB). ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant or degradation of pump performance. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of	Yes, Element 4 should be further evaluated How is sample size determined?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516. ***(7) Corrective Actions:*** Repairs are in conformance with IWA-4000, replacement according to IWA-7000, and reexamination in accordance with requirements of IWA-2200. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at flange connections where buildup of impurities can occur.	
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-G for pressure retaining welds in pumps. Water chemistry program based on EPRI guidelines of TR-105714 for minimizing impurities by monitoring and maintaining primary water chemistry.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of containment spray system components. ***(2) Preventive Actions:*** Selection of material in compliance with the guidelines of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential of SCC. However, inadvertent introduction of contaminants into the coolant system can occur, e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on intended function of the pump by control of primary water chemistry and by detection and sizing of cracks by ISI. Inspection requirements of IWC 2500-1 category C-G, specifies surface examination of either the inside or outside surface of all welds extending 1/2 in. on either side of the weld. In a group of multiple pumps of similar design, size, function, and service in a system, examination of only one pump is required. ***(4) Detection of Aging Effects:*** ~~Degradation of~~ pumps due to SCC can not occur ~~without~~ crack initiation and growth; ISI schedule ~~assures~~ detection of cracks before the loss of intended function ~~of~~ the pump. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWC-2400 should provide timely detection	No (NDE) ISI is not 100% fullproof Should

↓ ~~remove assures~~ insert should ~~and insert~~ should before assure

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) 89-04 and 96-05. IST is performed in accordance with ASME Subsection IWV (OM Code Appendix I and Subsection ISTC). ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant. ~~However, a one-time~~ inspection of representative sample of the system population ~~and most susceptible locations in the system should~~ be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516 for Class 2 components. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repairs are in conformance with IWA-4000 and repair according to IWA-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Corrosion has been observed in guide rings of relief valves (IN 98-23) and charging pump casing (IN 94-63).	
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-G for pressure retaining welds in Class 2 valves. Water chemistry program for minimizing impurities by monitoring and maintaining water chemistry conditions based on guidelines of EPRI TR-105714 for primary water chemistry.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and combination of inservice inspection (ISI) and inservice testing (IST) to monitor the effects of SCC on the intended function of containment spray system components. ***(2) Preventive Actions:*** Selection of material in compliance with the guidelines of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential of SCC. However, inadvertent introduction of contaminants into the coolant system can occur either e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely	No

V ENGINEERED SAFETY FEATURES

A. CONTAINMENT SPRAY SYSTEM (Pressurized Water Reactor)

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on the intended function of the valves by detection and sizing of cracks by ISI. Inspection requirements of Table IWC 2500-1, category C-G specify for all valves in each piping run examined under category C-F, surface examination of either the inside or outside surface of all welds extending 1/2 in. on either side of the weld. In a group of multiple valves of similar design, size, function, and service in a system, examination of only one valve is required. ***(4) Detection of Aging Effects:*** Degradation of valves due to SCC can not occur without crack initiation and growth; ISI schedule assures detection of cracks before the loss of intended function of the valves. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWC-2400 should provide timely detection of cracks. All welds are inspected each inspection period from at least one valve in each group with similar design and performing similar functions in the system. Visual examination is required only when the valve is disassembled for maintenance, repair, or volumetric examination, but at least once during the period. ***(6) Acceptance Criteria:*** Any SCC degradation is evaluated in accordance with IWC-3100 by comparing ISI results with the acceptance standards of IWC-3400 and IWC-3515 for surface examination of welds in Class 2 valves. ***(7) Corrective Actions:*** Repairs are in conformance with IWA-4000 and replacement according to IWA-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the primary pressure boundary piping of PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, cracking has occurred in safety injection lines (IN 97-19 and 84-18), internal bolting in swing check valves (IN 89-02), and safety-related SS piping systems which contain oxygenated, stagnant, or essentially stagnant borated water (IN 97-19).	
Same as effects of Corrosion/Boric Acid Wastage on containment spray system bolting (A.1.4).	*Same as effects of Corrosion/Boric Acid Wastage on containment spray system bolting (A.1.4).*	No
Plant specific aging management program.	**Plant specific aging management program is to be evaluated.**	**Yes, no AMP**

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) exchanger fails to perform adequately, corrective actions are taken in accordance with OM S/G Part 2. Root cause evaluation and appropriate corrective action are taken when acceptable limits are exceeded or leakage is detected. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Operating plant experience with this AMP indicates timely detection of corrosion in the containment spray heat exchangers.	
The program relies on preventive measures to mitigate corrosion by monitoring and control of water chemistry to minimize exposure to aggressive environments, and implementation of the recommendations of Generic Letter 89-13 or an equally effective program to ensure that open-cycle cooling water system is in compliance with General Design Criteria and Quality Assurance requirements. Water chemistry control program based on EPRI TR-105714 for primary water and plant technical specifications for cooling water.	***(1) Scope of Program:*** The program includes monitoring and control of water chemistry to minimize exposure to aggressive environments, and staff recommendations of Generic Letter (GL) 89-13 or an equivalent program provide assurance that open-cycle cooling water system is in compliance with General Design Criteria and Quality Assurance requirements. Guidelines of GL 89-13 include (a) surveillance and control of biofouling, (b) test program to verify heat transfer capabilities, (c) routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling, can not degrade the performance of safety-related systems serviced by open-cycle cooling water, (d) system walkdown inspection to ensure compliance with licensing basis, and (e) review of maintenance, operating, and training practices and procedures. ***(2) Preventive Actions:*** The component is constructed of appropriate materials, control of secondary side water chemistry, and lining or coating protect the underlying metal surfaces from being exposed to aggressive cooling water environment. Based on GL 89-13 cooling water system is continuously chlorinated or treated with biocide whenever the potential for biological fouling species exists. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by surveillance program to detect coolant leakage and inservice testing to evaluate component performance. Based on recommendations of GL 89-13 or its equivalent, cooling water system is inspected for biofouling organisms, sediment, protective coating failure, and corrosion; and cooling water flow and temperature are monitored for component performance evaluation to ensure that flow blockage or excessive fouling accumulation does not exist. ***(4) Detection of Aging Effects:*** Degradation of component due to corrosion would result in leakage of coolant or degradation of component performance; extent and schedule of inspection/testing assure detection of corrosion before the loss of intended function of the component. ***(5) Monitoring and Trending:*** Results from performance tests to verify heat transfer capabilities are trended. ***(6) Acceptance Criteria:*** Any relevant conditions related to corrosion or leakage are compared to established acceptable limits. Maximum levels for various impurities in secondary side water and cooling water	No

B Standby Gas Treatment System (Boiling Water Reactor)

B.1 Ductwork and Dampers

B.2 Electric Heater

B.3 Filters

B.3.1 Filter Housing and Supports

B.3.2 Charcoal Absorber Filter

B.3.3 Elastomer Seals

B.4 Fan

C. Containment Isolation Components

- C.1 Personnel Hatch
  - C.1.1 Hatchway
  - C.1.2 Inner Door
  - C.1.3 Outer Door
- C.2 Equipment Hatch
  - C.2.1 Hatchway
  - C.2.2 Cover Plate
- C.3 Mechanical (pipe) Penetrations
  - C.3.1 Sleeve
  - C.3.2 Seal
  - C.3.3 Closure Plate
  - C.3.4 Anchors
  - C.3.5 Fasteners
- C.4 Electrical Penetrations
  - C.4.1 Sleeve
  - C.4.2 Header Plate
  - C.4.3 Seal
  - C.4.4 Anchors
- C.5 Fuel Transfer Penetrations
  - C.5.1 Sleeve
  - C.5.2 Closure Plate
  - C.5.3 Anchors
- C.6 Purge/Vent

C.6.1 Seal

C.7 Leak Testing (Penetration, Integrated, & Isolation Valve Leak Test Systems)

C.7.1 Mechanical Penetrations

C.7.2 Sleeves

C.7.3 Seal

C.8 Isolation Barriers - Valves (BWR, in Lines for Emergency Core Cooling Systems, Feedwater, Main Steam)

C.8.1 Body

C.8.2 Bonnet

C.9 Isolation Barriers - Valves (PWR, in Lines for Emergency Core Cooling Systems, Feedwater, Auxiliary Feedwater, Main Steam, and Blowdown Piping)

C.9.1 Body

C.9.2 Bonnet

C.10 Isolation Barriers - Valves (BWR & PWR, in Lines for Fire Protection, Plant Heating, Waste Gas, Plant Drain, Liquid Waste, & Cooling Water)

C.10.1 Body

C.10.2 Bonnet

V ENGINEERED SAFETY FEATURES

C. CONTAINMENT ISOLATION COMPONENTS

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
C.1.1 thru C.1.3	Personnel Hatch	Hatchway, Inner Door, Outer Door	Carbon steel (Coating)	Air: Occasional Leaking Borated Water (PWRs) or Oxygenated Water (BWRs)	Loss of Material	General Corrosion	ASME Code Section XI, 1992 Edition. 10 CFR 50 Appendix J. Regulatory Guide 1.54. ANSI 101.2. ANSI 101.4. *Operating Experience* NRC IN 89-79.

not on reference list

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repair is in conformance with IWA-4000 and replacement according to IWA-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur.	
Program delineated in NUREG-0313, Rev. 2 and implemented through NRC Generic letter (GL) 88-01, and inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWB 2500-1, examination categories B-M-1 and B-M-2 for Class 1 valves; Table IWC 2500-1, examination category C-G for pressure retaining welds in Class 2 valves. Coolant water chemistry is monitored and maintained in accordance with EPRI guidelines in TR-103515 and BWRVIP-29 to minimize the potential of crack initiation and growth. Also, the integrity of the containment isolations valves is verified in Type C leak rate tests in accordance with Appendix J of 10 CFR 50.	***(1) Scope of Program:*** The program includes implementing counter measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and combination of inservice inspection (ISI) to monitor SCC and its effects on the intended function of valves. NUREG-0313 and GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigating IGSCC in BWRs. ***(2) Preventive Actions:*** Mitigation of IGSCC is by selection of material considered resistant to sensitization and IGSCC, e.g., low-carbon grades of cast SSs and weld metal, with a maximum carbon of 0.035% and minimum 7.5% ferrite. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors SCC of valves by detection and sizing of cracks by implementing the inspection schedule, methods, personnel, sample expansion, and leak detection requirements of GL 88-01. In a group of multiple valves of similar design, size, function, and service in a system, examination of only one valve is required. Coolant water chemistry is monitored and maintained in accordance with the EPRI guidelines in BWRVIP-29 to minimize the potential of crack initiation and growth. ***(4) Detection of Aging Effects:*** Degradation of valves due to SCC can not occur without crack initiation and growth; ISI ~~schedule~~ delineated in the AMP is adequate and ~~will~~ assure detection of cracks or degradation of valve performance before the loss of intended function of valves. should ***(5) Monitoring and Trending:*** Inspection schedule in accordance with GL 88-01 should provide timely detection of cracks. All welds are inspected each inspection period from at least one valve in each group with similar design and performing similar functions in the system. Visual examination is performed only when the valve is disassembled for maintenance, repair, or volumetric examination, but at least once during the period. ***(6) Acceptance Criteria:*** Any SCC degradation is evaluated in accordance with IWC-3100 by comparing ISI results with the acceptance standards of IWC-3400 and IWC-3515. ***(7) Corrective Actions:*** Repair is in conformance with IWA-4000 and replacement is in accordance with IWA-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** The	No

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWB-3100 and acceptance standards of IWB-3400 and IWB-3522 for Class 1 components, IWC-3100 and acceptance standards of IWC-3400 and IWB-3516 for Class 2 components, IWD-3000 for Class 3 components. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Corrosion has been observed in guide rings of relief valves (IN 98-23) and charging pump casing (IN 94-63).	
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWB 2500-1, examination categories B-M-1 and B-M-2 for Class 1 valves; Table IWC 2500-1, examination category C-G for pressure retaining welds in Class 2 valves. Water chemistry program for minimizing impurities by monitoring and maintaining water chemistry conditions based on guidelines of EPRI TR-105714 for primary water chemistry. Also, the integrity of the containment isolations valves is verified in Type C leak rate tests in accordance with Appendix J of 10 CFR 50.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of emergency core cooling system components. ***(2) Preventive Actions:*** Selection of material in compliance with the requirements of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential of SCC. However, inadvertent introduction of contaminants into the coolant system can occur, e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84–18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on intended function of the valves by detection and sizing of cracks by ISI. Inspection requirements of Table IWB 2500-1 for Class 1 valves, examination category B-M-1 specify for all welds NPS 4 or larger, volumetric examination extending 1/2 in. on either side of the weld and through wall thickness, and for welds less than NPS 4, surface examination of OD surface extending 1/2 in. on either side of the weld. Category B-M-2 specifies visual VT-3 examination of internal surfaces of the valve. Table IWC 2500-1 for Class 2 valves, category C-G specifies for all valves in each piping run examined under category C-F, surface examination of either the inside or outside surface of all welds extending 1/2 in. on either side of the weld. In a group of multiple valves of similar design, size, function, and service in a system, examination of only one valve is required. ***(4) Detection of Aging Effects:*** Degradation of valves due to SCC can not occur without crack initiation and growth; ISI schedule ~~assures~~ should detection of cracks or	No

D1 Emergency Core Cooling System (Pressurized Water Reactor)

D1.1 Piping & Fittings

- D1.1.1 Core Flood System (CFS)
- D1.1.2 Residual Heat Removal (RHR) or Shutdown Cooling (SDC)
- D1.1.3 High Pressure Safety Injection (HPSI)
- D1.1.4 Low Pressure Safety Injection (LPSI)
- D1.1.5 Connecting lines to Chemical & Volume Control System (CVCS) & Spent Fuel Pool (SFP) Cooling
- D1.1.6 Lines to Emergency Sump
- D1.1.7 Bolting for Flange Connections

D1.2 HPSI & LPSI Pumps

- D1.2.1 Bowl/Casing
- D1.2.2 Bolting

D1.3 RWT Circulation Pump

- D1.3.1 Bowl/Casing
- D1.3.2 Bolting

D1.4 Valves

- D1.4.1 Body and Bonnet
- D1.4.2 Bolting

D1.5 Heat Exchangers (RCP, HPSI, & LPSI Pump Seals; & RHR)

- D1.5.1 Bonnet/Cover
- D1.5.2 Tubing
- D1.5.3 Shell
- D1.5.4 Case/Cover
- D1.5.5 Bolting

D1.6 Heat Exchangers (RWT Heating)

- D1.6.1 Bonnet/Cover
- D1.6.2 Tubing
- D1.6.3 Shell
- D1.6.4 Bolting

D1.7 Safety Injection Tank (Accumulator)

- D1.7.1 Shell
- D1.7.2 Manway
- D1.7.3 Penetrations/Nozzles

D1.8 Refueling Water Tank (RWT)

- D1.8.1 Shell
- D1.8.2 Manhole
- D1.8.3 Penetrations/Nozzles
- D1.8.4 Bolting
- D1.8.5 Perimeter Seal

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) of IWA-2200. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the primary pressure boundary piping of PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, potential of SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84-18). SCC has been observed in safety injection lines (IN 97-19 and 84-18), charging pump casing cladding (INs 80-38 and 94-63), and instrument nozzles in safety injection tanks (IN 91-05).	
Inservice inspection is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWB 2500-1, testing category B-P for pressure retaining Class 1 components, e.g., CFS and other components within the containment; Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components, e.g., most components in the safety injection system; and Table IWD 2500-1, test and examination category D-B for systems in support of emergency core cooling, e.g., refueling water tank (RWT) heating system. Water chemistry program for minimizing impurities by monitoring and maintaining water chemistry conditions based on guidelines of EPRI TR-105714 for primary water chemistry and plant technical specifications for refueling water storage tank water chemistry.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and inservice inspection (ISI) to monitor the effects of corrosion on the intended function of emergency core cooling system components. ***(2) Preventive Actions:*** Control of halogens, sulfates, and oxygen in the primary water to less than 0.05, 0.05, and 0.005 ppm, respectively, during operation, and monitor and control of water chemistry during shut down. However, inadvertent introduction of contaminants into the coolant system can occur either e.g., contaminants in the boric acid, or introduced through the free surface of spent fuel pool [NRC Information Notice (IN) 84-18], or from water from the sump. The AMP must therefore rely upon ISI in accordance with ASME Section XI to detect possible degradation. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by control of system water chemistry and by detection of coolant leakage by inservice inspection (ISI). Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 1 components according to Table IWB 2500-1 category B-P; Class 2 components required to operate or support the safety function according to Table IWC 2500-1 category C-H; and Class 3 components in support of emergency core cooling according to Table IWD 2500-1 category D-B. ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic,	Yes, Element 4 should be further evaluated

How is the sample determined?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components, and water chemistry control program based on plant technical specifications.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of the RWT. ***(2) Preventive Actions:*** Selection of material in compliance with the requirements of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of SCC on intended function of the RWT by detection of leakage. Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage test and system hydrostatic test of all pressure retaining Class 2 components required to operate or support the safety function, according to Table IWC 2500-1 category C-H. ***(4) Detection of Aging Effects:*** Degradation of the component due to SCC can not occur without leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516. Any evidence of aging effects or unacceptable results are evaluated. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** SCC has been observed in safety injection lines (IN 97-19 & 84-18), charging pump casing cladding (INs 80-38 and 94-63), and instrument nozzles in safety injection tanks (IN 91-05).	Yes, Element 4 should be further evaluated ?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, test and examination category D-B for systems in support of emergency core cooling, and water chemistry control program based on plant technical specifications.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and inservice inspection (ISI) to monitor the effects of corrosion on the intended function of emergency core cooling system components. ***(2) Preventive Actions:*** Control of water chemistry based on plant technical specifications. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by detection of coolant leakage by ISI. Inspection requirements of ASME Section XI, Table IWD 2500-1, category D-B specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 3 components in support of emergency core cooling. ***(4) Detection of Aging Effects: :*** Degradation of the component due to corrosion would result in leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWD-3000 for Class 3 components. Any evidence of aging effects or unacceptable results are evaluated. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevices that may allow buildup of impurities due to stagnant conditions.	Yes, Element 4 should be further evaluated
Guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWD 2500-1, test and examination category D-B for systems in support of emergency core cooling, and water chemistry control program based on plant technical specifications.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of the RWT. ***(2) Preventive Actions:*** Selection of material in compliance with the requirements of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of water chemistry is based on plant technical specifications. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of SCC on intended function of the RWT by	Yes, Element 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) detection of leakage. Inspection requirements of ASME Section XI, Table IWD 2500-1, category D-B specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 3 components in support of emergency core cooling. ***(4) Detection of Aging Effects:*** Degradation of the component due to SCC can not occur without leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** Inspection schedule of ASME Section XI should provide for timely detection of leakage. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWD-3000 for Class 3 components. Any evidence of aging effects or unacceptable results are evaluated. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the primary pressure boundary piping of PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, significant potential of SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84-18). SCC has been observed in safety injection lines (IN 97-19 and 84-18), charging pump casing cladding (INs 80-38 and 94-63), internal bolting in swing check valves (IN 89-02), and instrument nozzles in safety injection tanks (IN 91-05).	
Same as effect of Corrosion/Boric Acid Wastage of Item D1.1.7 Bolting for flange connections in Items D1.1.1 thru D1.1.5.	*Same as effect of Corrosion/Boric Acid Wastage of Item D1.1.7 Bolting for flange connections in Items D1.1.1 thru D1.1.5.*	No

D2 Emergency Core Cooling System (BWR)

D2.1 Piping & Fittings

D2.1.1 High Pressure Coolant Injection (HPCI)

D2.1.2 Reactor Core Isolation Cooling (RCIC)

D2.1.3 High-Pressure Core Spray (HPCS)

D2.1.4 Low-Pressure Core Spray (LPCS)

D2.1.5 Low Pressure Coolant Injection (LPCI) or Residual Heat Removal (RHR)

D2.1.6 Lines to Spent Fuel Pool (SFP) and Suppression Chamber (SC)

D2.1.7 Lines to Containment Spray System (CSS)

D2.1.8 Automatic Depressurization System (ADS)

D2.1.9 Lines to HPCI and RCIC Pump Turbine

D2.1.10 Lines from HPCI and RCIC Pump Turbines to Condenser

D2.2 Pumps (HPCS or HPCI Main & Booster, LPCS, LPCI or RHR, & RCIC)

D2.2.1 Bowl/Casing

D2.2.2 Suction Head

D2.2.3 Discharge Head

D2.3 Valves (Check, Control, Hand, Motor Operated, & Relief Valves)

D2.3.1 Body and Bonnet

D2.4 Heat Exchangers (RHR & LPCI)

D2.4.1 Tubes

D2.4.2 Tubesheet

D2.4.3 Channel Head

D2.4.4 Shell

D2.5 Header and Spray Nozzles System

D2.5.1 Piping and Fittings

D2.5.2 Flow Orifice

D2.5.3 Headers

D2.5.4 Spray Nozzles

D2.6 Isolation Condenser

D2.6.1 Tubing

D2.6.2 Tubesheet

D2.6.3 Channel Head

D2.6.4 Shell

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Water chemistry program based on EPRI guidelines of TR-103515 and implemented through the plant technical specifications for minimizing impurities by monitoring and maintaining water chemistry conditions, and inservice inspection is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate general, crevice, and pitting corrosion and inservice inspection (ISI) to monitor the effects of corrosion on emergency core cooling system components. ***(2) Preventive Actions:*** Mitigation is by monitoring and control of water chemistry to minimize concentration of corrosive impurities in accordance with the EPRI guidelines of TR-103515. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by detection of coolant leakage by inservice inspection (ISI). Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic tests of all pressure retaining Class 2 components according to Table IWC 2500-1 category C-H. ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. ***(5) Monitoring and Trending:*** System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516 for Class 2 components. Any evidence of aging effects or unacceptable results are evaluated. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repair are in conformance with IWA-4000 and IWB-4000 and replacement according to IWA-7000 and IWB-7000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at mechanical joints, because of crevice geometry at the sealing surfaces that may allow buildup of impurities due to stagnant conditions. No significant corrosion related problem has been reported for piping and fittings in BWR emergency core cooling system.	Yes, Element 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Wall-thinning problems in two-phase piping have occurred in extraction steam lines (INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (INs 89-53, 91-18, 93-21, 97-84).	
Water chemistry program based on EPRI guidelines of TR-103515 and implemented through the plant technical specifications for minimizing impurities by monitoring and maintaining water chemistry conditions; inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components; and based on the testing requirements of 10 CFR 50.55a for ASME Code Class 2 pumps, and additional NRC staff guidelines of NRC Generic Letter 89-04, inservice testing performed in accordance with ASME Subsection IWP (or Operation and Maintenance Code Subsection ISTB) for pumps, or other approved program in the plant specifications.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate general, crevice, and pitting corrosion and combination of inservice inspection (ISI) and inservice testing (IST) to monitor the effects of corrosion on the intended function of emergency core cooling system components. ***(2) Preventive Actions:*** Mitigation is by monitoring and control of water chemistry to minimize concentration of corrosive impurities in accordance with EPRI guidelines of TR-103515 and implemented through the plant technical specifications. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of corrosion by ISI to detect coolant leakage and IST to evaluate component performance. Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage test and hydrostatic test of all pressure retaining Class 2 components according to Table IWC 2500-1 category C-H. Based on the requirements of 10 CFR 50.55a for ASME Code Class 2 pumps and additional guidelines of NRC Generic Letter (GL) 89-04, IST is performed in accordance with ASME Subsection IWP (or OM Code Subsection ISTB). ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant or degradation of component performance. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. ***(5) Monitoring and Trending:*** ISI/IST schedule of ASME Section XI should provide for timely detection of corrosion. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. The results of one-time inspection should be used to dictate the frequency of future inspections. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWB-3516 for Class 2 components. Any evidence of aging effects or unacceptable results are evaluated. ***(7) Corrective Actions:*** Prior to service,	Yes, Element 4 should be further evaluated

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repair and replacement are in conformance with IWA-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at flange connections and other crevices where buildup of impurities can occur. No significant corrosion related problem has been reported for pumps in BWR emergency core cooling system.	
Same as for Erosion/Corrosion of Item D2.1.9 lines to HPCI & RCIC pump turbine and D2.1.10 lines from HPCI & RCIC pump turbine to condenser.	*Same as for Erosion/Corrosion of Item D2.1.9 lines to HPCI & RCIC pump turbine and D2.1.10 lines from HPCI & RCIC pump turbine to condenser.*	Yes, Element 1 should be further evaluated
Water chemistry program based on EPRI guidelines of TR-103515 and implemented through the plant technical specifications for minimizing impurities by monitoring and maintaining water chemistry conditions; inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-H for pressure retaining Class 2 components; and based on the testing requirements of 10 CFR 50.55a for ASME Code Class 2 valves, staff guidelines of NRC Generic Letter (GL) 89-04 regarding the scope of inservice testing (IST), and information in NRC IN 88-70 regarding scope and testing of safety-related check valves, and in GL 96-05 regarding safety-related motor-operated valves, IST is performed in accordance with ASME Subsection IWV (Operation and Maintenance Code Appendix I and Subsection ISTC), to ensure that the changes in design-basis performance of safety-related valves resulting from degradation can be identified and managed.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and combination of inservice inspection (ISI) and inservice testing (IST) to monitor the effects of corrosion on the intended function of emergency core cooling system components. ***(2) Preventive Actions:*** Mitigation is by monitoring and control of water chemistry to minimize concentration of corrosive impurities by following EPRI guidelines of TR-103515 and implemented through the plant technical specifications. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of corrosion by ISI to detect coolant leakage and IST to evaluate component performance. Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage test and hydrostatic test of all pressure retaining Class 2 components, according to Table IWC 2500-1 category C-H. Based on the requirements of 10 CFR 50.55a for ASME Code Class 2 valves and additional guidelines of NRC GLs 89-04 and 96-05, IST is performed in accordance with ASME Subsection IWV (OM Code Appendix I and Subsection ISTC). ***(4) Detection of Aging Effects:*** Degradation of the component due to corrosion would result in leakage of coolant or degradation of component performance. However, a one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. ***(5) Monitoring and Trending:*** ISI/IST	Yes, Element 4 should be further evaluated

E Fan Cooler System

E.1 Fan Coolers

E.1.1 Cooling Coils

E.1.2 Fan Housing

E.1.3 Blades

E.1.4 Fasteners

E.1.5 Piping

E.1.6 Fittings

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Why aren't all the EPRI reports listed together

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CHAPTER VI

ELECTRICAL COMPONENTS

Major Electrical Components

A. Electric Cables

B. Electrical Connectors

C. Electrical Penetration Assemblies

D. Electrical Buses

E. Electrical Insulators

F. Transmission Conductors

G. Ground Conductors / Ground Grid

A. Electric Cables

A.1 Power, Instrumentation and Control Cables
- A.1.1 Conductor
- A.1.2 Shield Wire
- A.1.3 Insulation
- A.1.4 Jacket

Not necessarily true. They may utilize similar materials but not similar constructions. Medium voltage cables normally utilize ground wires/shields etc.

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Systems, Structures and Components

This review table addresses electric cables, including power, instrumentation and control (I&C) cables. The power cables addressed are low-voltage (< 1000 V) and medium voltage (2 kV to 15 kV), ~~which have similar constructions to I&C cables.~~ High voltage power cables (>15 kV) have unique, specialized construction and must be evaluated on an application specific basis. Since the cable types addressed herein are very similar in ~~construction and~~ aging effects, they are grouped together in the table. Individual sub-components for a typical cable are addressed in terms of aging mechanisms and effects.

System Interfaces

Electric cables functionally interface with all plant systems that rely on electric power and/or instrumentation and control. Physical interfaces include routing in cable trays and conduits.

* Include a section on aging management of "inaccessible" and "buried" cables.

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References *
A.1.1	Power, Control, & Instrument Cables	Conductor	Copper • coated or non-coated • stranded or solid	Humid, Chemical Exposure Add Tempe-rature	Increased circuit resistance, heating, signal noise, circuit failure ~~Add Open circuit~~	Corrosion	IE Bulletin 79-1B (DOR Guideline) NUREG-0588 IEEE Standards • 323-1971 • 323-1974 • 383-1974 • 317-1976 • 338-1987 • 1205-1993 Regulatory Guide 1.89, Rev. 1 10CFR50.49 EQ Rule

* These references are pertinent to the electrical components in Chapter VI. They are not relevent to "conductor."

time-temperature and radiation equivalent preaging

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Cables

Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified ~~Equipment~~ Cables For electrical equipment that is environmentally qualified for use in nuclear power plants, the environmental qualification program may be applicable as a tool for aging management. **Environmental Qualification (10CFR50.49: EQ Rule)** EQ requirements have evolved over the years; therefore, plants of various vintages are licensed based on different EQ requirements. There are three main documents that chronicle the EQ requirements, starting with the IE Bulletin 79-01B (DOR guidelines) issued in 1979. This was followed by NUREG-0588, which specifies two categories of qualifications, and finally the current EQ Rule (10 CFR 50.49). The DOR Guidelines and NUREG-0588 Category II are consistent with the original IEEE Standard for qualifying Class 1E equipment (IEEE Std 323-1971), while NUREG-0588 Category I and 10 CFR 50.49 endorse a later version of the standard (IEEE Std 323-1974). IEEE Standard 323-1974 includes more stringent requirements than the 1971 version, including the application of margins to test parameters and pre-aging of equipment prior to accident testing. It should be noted that the NRC has not endorsed a later version of the standard (IEEE Std 323-1983). While many of the older vintage plants were licensed based on the DOR Guidelines/NUREG-0588, Category II, many of the electric cables inside containment (over 70%) included pre-aging as part of their original qualification, or have been re-qualified to Category I criteria. Many older plants still utilize cable connections and electrical penetrations that were environmentally qualified in accordance with the DOR Guidelines and/or the NUREG-0588, Category II requirements. The original qualification of many of these components might not have included pre-aging prior to exposing them to accident conditions.	**A. Environmentally Qualified ~~Equipment~~** Cables In general, the EQ process accounts for aging through the use of ~~a Time Limited Aging Analysis (TLAA)~~ time-temperature and radiation equivalent preaging for the equipment to be qualified. It does not require the use of prevention or mitigation measures, or the use of condition/performance monitoring. Therefore, EQ cannot be considered a typical aging management program. However, the TLAA does provide some assurance that the effects of aging will not be problematic during the qualified life of the equipment. As such, EQ can be considered part of an aging management program for license renewal if the licensee can show i) the TLAA remains valid for the period of extended operation, ii) the TLAA is projected to the end of the period of extended operation through re-analysis, or iii) the effects of aging on the intended function(s) will be adequately managed during the period of extended operation. For case (i), the existing qualification is acceptable for extended life and no further evaluation is necessary. For case (ii), a re-analysis is necessary to extend the qualified life of the equipment. In the re-analysis, attributes that should be addressed include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions if acceptance criteria are not met, and the period of time prior to the end of qualified life when the re-analyses will be completed For ~~In light of~~ case (iii), the EQ process is ~~was~~ evaluated as an aging management program based on the 10 criteria identified in the draft SRP-LR. The following summarize this evaluation: *(1) Scope of Program:* The EQ requirements apply to electric equipment important to safety, which includes those electrical components within the scope of license renewal (i.e., cables, connectors, and penetration assemblies). ***(2) Preventive Actions:*** EQ does not require the use of preventive actions to manage the effects of aging. Aging is addressed through the use of a TLAA. As such, the EQ process identifies no preventive actions. ***(3) Parameter Monitored/Inspected:*** EQ is not a condition or performance monitoring program. As such, it does not identify any parameters to be monitored to manage the effects of aging. Aging is addressed through the use of a TLAA. ***(4) Detection of Aging Effects:*** In general, EQ does not require the detection of aging effects for equipment while in service. ~~When the qualified life is less than the current plant license period, EQ requires a program to replace or refurbish the component at the end of its qualified life.~~ ~~intended service life~~ ***(5) Monitoring and Trending:*** EQ does not rely on monitoring and trending of condition or performance parameters of equipment while in service to manage the effects of aging. As such, no monitoring or trending activities for assessing	**A. Environmentally Qualified Equipment** Yes. In the case where the TLAA is projected to the end of the period of extended operation, the analysis attributes identified should be addressed

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
operability	the impact on equipment condition due to aging are identified by the EQ process. It should also be noted that currently, there are no recognized in situ condition monitoring methods that are effective for monitoring the condition of electric cables. Research is ongoing to determine if acceptable methods exist. ***(6) Acceptance Criteria:*** EQ does not rely on monitoring and trending of condition or performance parameters to manage the effects of aging. As such, no acceptance criteria are established for equipment ~~operation~~ while in service. ***(7) Corrective Actions:*** As part of the EQ process, a qualified life is established for the equipment being qualified. Once the equipment reaches the end of its qualified life, the only acceptable corrective action is refurbishment or replacement. ***(8 & 9) Confirmation process and Administrative Controls:*** EQ does not rely on preventive or corrective actions to address the effects of aging. As such, the EQ process identifies no confirmation process. EQ documentation for each qualified component is maintained at the plant site in an auditable form for the duration of the installed life of the equipment. ***(10) Operating Experience:*** Passive electrical components are typically reliable devices under normal plant conditions and have very little evidence of significant failures. In a study performed by Sandia (SAND96-0344, 9/96), a database of nuclear plant component failure records was reviewed to identify relative number of failures, as well as typical failure modes and causes for electrical cables and terminations. The review covered data for the time period from 1975 to 1994, and generated 1,458 reports applicable to low and medium voltage cables and terminations. An analysis of these records showed the following: - In general, these components have good reliability. However, aging degradation does occur and has led to failures. - For low-voltage components, connectors accounted for the highest percentage of failures (30%). Cables (14.5%), terminal blocks (3.5%) and splices (2.5%) had relatively fewer failures. - For medium voltage components cables had the highest percentage of failures (69%), followed by connectors (11%) and splices (17%). - Most of the failures are detected by operation of the component; relatively few are detected by maintenance or surveillance. Another EPRI study on low-voltage environmentally qualified cables presented in an industry report (EPRI TR-103841, 6/94) analyzed Licensee Event Reports for the period from 1968 to June 1992. Only 87 LERs related to cables were considered attributable to aging and the failures were categorized as follows: thermal degradation (13 reports), mechanical damage (23 reports), misapplication (11 reports), and unknown (40 reports). Roughly half of these failures occurred in the first 6 years of operation, and the number of failures decreased significantly after 10 years of operation.	

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	NRC's aging assessment on cables, connections, and electrical penetration assemblies analyzed LER/NPE data for the period from mid-1980 to 1988 (NUREG/CR-5461, 6/90). An analysis of these failure data showed the following: • Out of 151 reported events on cables, more than 70% involved some type of electrical failure, either shorting, open circuit, or grounding faults. • Out of 196 reported events on connections, almost 80% involved shorted, grounded, loose, or open connections. • Out of 39 reported events on EPAs, pressure leakage (41%) and electrical failure (26%) caused the most events. Based on the results presented by these studies, it is seen that qualified electrical equipment does have good reliability, and aging degradation is usually well managed. These components receive little or no preventative maintenance. Under accident conditions, however, the reliability of these components is relatively unknown. Many of the causes of failures in accident conditions would not be detected during normal operation because of the absence of high temperatures and humidity. Note that not all degradation is detected and mitigated before it results in failure. Therefore, additional aging management practices are needed to completely manage the effects of aging for these electrical components. As discussed in SECY-93-049, during the staff's review of license renewal issues, the EQ process was found to be a significant issue. Of particular concern was whether the EQ requirements for older plants (i.e., DOR guidelines, NUREG-0588 Cat. II), whose licensing bases differ from newer plants, are adequate for license renewal. Further, a question was raised as to whether the EQ requirements for older plants should be reassessed for the current licensing term. Upon subsequent review, additional concerns were raised related to the EQ process, and it was concluded that differences in EQ requirements constituted a potential generic issue that should be evaluated for backfit, independent of license renewal. This came to be identified as Generic Issue 168. Key items to be addressed in GSI-168 are: • The adequacy of older EQ requirements for license renewal, as well as for the current licensing term • The adequacy of accelerated aging techniques to simulate long-term natural service aging • The possibility that unique failure mechanisms exist for bonded jacket and multi-conductor cable configurations that are not adequately addressed in EQ • The feasibility of using condition monitoring (CM) techniques to monitor current cable condition in situ as a means of offsetting uncertainties in the process used to predict long-term service aging Presently, GSI-168 is an open generic issue [that includes consideration for] ~~related to~~ license renewal, and research is ongoing to provide information to resolve it. Specific issues being addressed in this research are presented in	

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	NUREG/CR-6384. Once this generic issue is resolved, guidance will be provided ~~as to the impact on~~ license renewal. ~~In the interim, NRC letter dated June 2, 1998 "Guidance on Addressing GSI-168 for License Renewal," (C. Grimes, NRC to D. Walters, NEI) provides guidance on addressing GSI-168 in license renewal applications. It states that, until the generic issue is resolved,~~ "*An acceptable approach described in the SOC is to provide a technical rationale demonstrating that the current licensing basis for EQ, pursuant to 10 CFR 50.49 will be maintained in the period of extended operation.*" It should be noted that, currently, there are no acceptable non-destructive CM techniques to measure the integrity of electric cables in situ. ~~It does not appear that~~ utilities can take credit for current functional testing of cables by periodic system or circuit testing as a means of satisfying the criteria for an item to be considered a replacement item. The effectiveness of several promising CM techniques for monitoring degradation of cables is the subject of an ongoing NRC research program. The results of this program will be part of the resolution of GSI-168.	
B. <u>Non-environmentally Qualified ~~Equipment~~</u> In many applications, electrical ~~equipment~~ may not be environmentally qualified, and other aging management programs may be applicable. The following are examples. **Aging Inspection Program** For those electrical components that are accessible, a visual inspection can be used to provide some indication of aging degradation. The visual inspection can check for surface anomalies, such as discoloration, cracking or surface contamination that would indicate the presence of ~~active~~ aging degradation. For cables, if the jacket or insulation can be touched, a qualitative indication of material hardening can be made. Observation of aging degradation would indicate the need for further investigation of the component. **Instrument Calibration Program** Instrument calibration programs, including technical specification surveillance, may be used to provide an indirect indication of the condition of ~~various electrical components~~. If calibration drift is noted for instruments, this could be an indication that aging degradation is affecting the electrical circuit. Further investigation could then be initiated to determine the nature of the degradation and the component affected.	**B. <u>Non-environmentally Qualified Equipment</u>** The aging management programs discussed are generic in nature and should be developed based on specific plant applications. These programs will be evaluated on a plant specific basis.	**B. <u>Non-environmentally Qualified Equipment</u>** Yes. A plant specific evaluation is required.

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
A.1.2	Power, Control, & Instrument Cables	Shield Wires	Braided copper, Aluminum Foil, Metallized mylar tape	Humid, Chemical Exposure	Signal noise or error in control and instrumnt. cable	Corrosion	*Same as effect of corrosion on conductor for cables (A.1.1).*
A.1.3	Power, Control, & Instrument Cables	Insulation	Polymers such as XLPE, EPR, SR	Humid, High voltage gradient (Power Cable) Add Temperature, Radiation	Loss of dielectric strength, signal noise/ error, leakage current	Moisture diffusion/ absorption; Formation of water trees in power cables Add Embrittlement	*Same as effect of corrosion on conductor for cables (A.1.1).*

change the word "Equipment" to "Cables"

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* Note: The most probable location for shield wire corrosion is at exposed sites, such as terminations on equipment or terminal strips	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1)*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* Note: Underwater cables or cables with prolonged exposure to humid environment, should be specifically designed for such applications.	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A.1.3	Power, Control, & Instrument Cables	Insulation	Polymers such as XLPE, EPR, SR	High temp., Radiation, Oxygen, and Internal Ohmic heating (Power Cables)	Loss of dielectric strength, leakage current, signal noise/ error, circuit failure	Hardening, Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).*

Change the word "Equipment" to "Cables".

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
<u>A. Environmentally Qualified Equipment</u> *Same as effect of corrosion on conductor for cables (A.1.1).*	**<u>A. Environmentally Qualified Equipment</u>** *Same as effect of corrosion on conductor for cables (A.1.1).*	**<u>A. Environmentally Qualified Equipment</u>** *Same as effect of corrosion on conductor for cables (A.1.1).*
<u>B. Non-environmentally Qualified Equipment</u> *Same as effect of corrosion on conductor for cables (A.1.1).*	**<u>B. Non-environmentally Qualified Equipment</u>** *Same as effect of corrosion on conductor for cables (A.1.1).* <u>Note:</u> Some applications use different insulation materials, such as mineral insulation and polyimides (e.g., Kapton) which may be susceptible to different aging mechanisms. Cracking can be initiated in a an embrittled cable by any movement of the cable, such as a seismic event, maintenance activities, or vibration from nearby operating equipment. While embrittlement and cracking of cable insulation may not affect cable performance under normal, dry conditions, the aging effects noted would be probable when cables with cracks are exposed to moisture, such as in a design basis event. Moisture intrusion through the cracks could lead to shorting and possible circuit failure.	**<u>B. Non-environmentally Qualified Equipment</u>** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A.1.4	Power, Control, & Instrument Cables	Jacket	Polymers such as Neoprene, CSPE, PVC	High temp., Radiation, Oxygen	Loss of mechanical and environ-mental protection to underlying insulation. Exposure of insulation to outside conditions.	Hardening, Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).*

Change the word "Equipment" to "Cables".

VI. **ELECTRICAL COMPONENTS**

A. Electric Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
B. Non-environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* Note: Jackets provide some degree of protection to underlying insulation from exposure to outside stressors, such as radiation, oxygen, moisture, dirt, dust and other contaminants. For bonded jacket cables, in which the jacket is bonded to the insulation, cracking in the jacket has been found to propagate through to the insulation in some cases.	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A.1.4	Power, Control, & Instrument Cables	Jacket	Polymers such as Neoprene, CSPE, PVC	High temp., Radiation, Oxygen	Loss of fire protection	Loss of fire retardant	*Same as effect of corrosion on conductor for cables (A.1.1).*

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
B. Non-environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* Note: The primary purpose of the jacket is to protect the insulated conductors from fire and environmental stressors. No known condition monitoring method is available to determine the amount of fire retardant lost with the age of the jacket material.	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A.1.4	Power, Control, & Instrument Cables	Jacket	Polymers such as Neoprene, CSPE, PVC	Vibration, maint-enance abuse	Exposure of insulation to outside conditions	Wear and tear	*Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
A. Electric Cables

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
B. Non-environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* Add a Section on Non-environmentally Qualified Cables (inaccessible or buried)	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* Note: Wear due to vibration is most probable in locations where jacket is adjacent to rough or sharp objects capable of causing cutting, chafing or abrasion. Jackets provide some degree of protection to underlying insulation from exposure to outside stressors, such as radiation, oxygen, moisture, dirt, dust and other contaminants.	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

B. Electrical Connectors

B.1 Splices
- B.1.1 Jackets
- B.1.2 Seals
- B.1.3 Insulators

B.2 Mechanical Connectors
- B.2.1 Terminal Lugs, compression fittings, fusion connectors, contact pins

B.3 Terminal Blocks
- B.3.1 Block Assembly

Systems, Structures and Components

This review table addresses the electrical connectors that are used in electrical circuits to join the various components electrically. This includes splices, mechanical connectors and terminal blocks. Individual sub-components for each connector are addressed in terms of aging mechanisms and effects.

System Interfaces

Electrical connectors are used in all electrical circuits, therefore, they functionally interface with all plant systems that rely on electric power and/or instrumentation and control. Physical interfaces include installation in junction boxes and various control panels.

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	~~References~~
B.1.1	Splices	Jackets	Polymers	High temp., Radiation, Oxygen Add Humidity, Contaminants.	Exposure of insulation and internal parts to outside conditions	Hardening and Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).* Confusing. Isn't there a specific IEEE Std. on Connectors? IEEE Std. 572-1985.
B.1.2	Splices	Seals (potting) Compounds (gaskets, sealant)	Organic Compounds or cement, Rubber	High temp., Radiation, Oxygen	Moisture intrusion, leakage current, Signal noise/ Error, circuit failure	Hardening and Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).*

Making everything same as effect of corrosion is confusing when you are discussing jackets or splices. Provide appropriate text or cross-references.

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
B. Non-environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
B. Non-environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B.1.2	Splices	Seals (potting) Compounds (gaskets, sealant)	Organic Compounds or cement, Rubber	High temp. hmidity, Mech. Stress	Moisture intrusion, leakage current, Signal noise/ Error, circuit failure	Creep, distortion	*Same as effect of corrosion on conductor for cables (A.1.1).*
B.1.3	Splices	Insulators (Heat shrink, Tape)	Organic materials, rubber, specialty tapes	High temp., Radiation, Oxygen	Leakage current, Signal noise/ Error, circuit failure	Hardening and Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B.2.1	Mechanical Connectors	Terminal lugs, compression fittings, Fusion connectors Contacts/ pins	Copper (plated/ Nonplated)	Moisture, chemicals, oxygen	Increased circuit resistance, leakage current, signal noise/ error Open-Circuit	Corrosion, oxidation	*Same as effect of corrosion on conductor for cables (A.1.1).*
B.2.1	Mechanical Connectors	Terminal lugs. compression fittings, fusion connectors, Contacts/ pins	Copper (plated/ Nonplated)	Vibration, thermal cycling, repeated connect/ disconnect	Increased circuit resistance, leakage current, signal noise/ error Open-Circuit	Distortion, cracking, work hardening	*Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

VI. ELECTRICAL COMPONENTS
B. Electrical Connectors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B.3.1	Terminal Blocks	Block assembly	Organic Compounds	High temp., Radiation, Oxygen	Shorting	Hardening, Cracking	*Same as effect of corrosion on conductor for cables (A.1.1).*
B.3.1	Terminal Blocks	Block assembly	Organic Compounds	Moisture, Contami-nants	Shorting	Loss of insulating properties	*Same as effect of corrosion on conductor for cables (A.1.1).*

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*
A. Environmentally Qualified Equipment *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*	**A. Environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).* **B. Non-environmentally Qualified Equipment** *Same as effect of corrosion on conductor for cables (A.1.1).*

C. Electrical Penetration Assemblies (EPA)

C.1 Modular EPA
- C.1.1 O-ring seals
- C.1.2 Conductor-to-insulator seals
- C.1.3 Cable lead wires
- C.1.4 Interface connectors

The EPA includes pipe segment, head plates and associated penetration cable sealing system, penetration cabling, pigtails to the field connection points.

Systems, Structures and Components

This review table addresses electric penetration assemblies (EPA). EPAs are used to route electric cable circuits through the containment wall. They provide electrical continuity for the circuit, as well as a pressure boundary for the containment. Individual sub-components for a typical modular type EPA are addressed in terms of aging mechanisms and effects.

System Interfaces

Electric penetration assemblies functionally interface with all electric circuits that must be routed through the containment wall.

VI. ELECTRICAL COMPONENTS
C. Electrical Penetration Assemblies

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
C.1.1	Modular Electrical Penetration Assemblies	O-ring seals	Organic compound	High temp., Radiation, Oxygen, Low Humidity	Loss of pressure boundary	Hardening, oxidation Creep due to thermal aging	*Same as effect of corrosion on conductor for cables (A.1.1).*
C.1.2	Modular Electrical Penetration Assemblies	Conductor-to-insulator seals	Fused glass/metal Fused epoxy/metal Mechanical swage	Moisture, Contami-nants	Loss of pressure boundary	Corrosion Creep	*Same as effect of corrosion on conductor for cables (A.1.1).*

E. Electrical Insulators

E.1 Station Post Insulators
E.1.1 Assembly

E.2 Strain/suspension Insulators
E.2.1 Assembly

VI. ELECTRICAL COMPONENTS
E. Electrical Insulators

Systems, Structures and Components

This review table addresses electric insulators, including station post insulators and suspension insulators. Station post insulators and suspension insulators form an integral part of the utility transmission system connecting the power station to offsite power sources, and tying the main generator output to the utility's power grid. Station post insulators provide electrical insulation, spacing, and support between sub-station and switchyard electrical buses and their support structures. Similarly, suspension insulators provide electrical insulation, spacing, and support between transmission line conductors and their transmission structures.

System Interfaces

and distribution

Electric insulators functionally interface with the utility transmission system connecting the power station to offsite power sources, and tying the main generator output to the utility's power grid

VI. ELECTRICAL COMPONENTS
E. Electrical Insulators

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E.1.1	Station post insulator	Assembly	Porcelain, Galvanized Metals, Stainless Steel, Cement Epoxy	High temperature, dirt, dust, salt, vibration, and humidity	Leakage current, loss of function, cracking flash-over	Surface contamination or oxidation, loss of material due to wear, corrosion, mechanical stress	IN 93-95

VI. ELECTRICAL COMPONENTS
E. Electrical Insulators

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Insulator Inspection Program While no requirement currently exists for such a program, periodic visual inspection of insulators is a potential method of managing aging degradation for these components. The inspection program should check for indications of any of the identified aging mechanisms, such as cracking or surface contamination. If no indications are found, this would provide some assurance that aging degradation is not adversely impacting the ability of the components to perform their intended function. If indications of aging degradation are noted, corrective actions can be taken prior to failure occurring.	As one potential means of managing aging of insulators, an inspection program can be implemented in which periodic visual inspections of the components are performed. The 10 criteria identified in the draft SRP-LR are discussed for such a program below: ***(1) Scope:*** The inspection program should include all insulators that are important to safety. ***(2) Preventive Actions:*** Any preventive actions that can be taken to mitigate aging degradation should be identified. ***(3) Parameter Monitored/Inspected:*** The parameters to be monitored/inspected should be determined based on the aging mechanisms identified as important for these components. Each of the aging mechanisms presented in this table should be addressed by identifying a parameter or indicator that can be observed during the inspection. ***(4) Detection:*** Each of the parameters/indicators should be observed during the inspection to provide some assurance that aging degradation is detected prior to failure. ***(5) Monitoring and Trending:*** Any aging indicators noted during the inspection should be quantified, to the extent possible, to allow trending in future inspections. ***(6) Acceptance Criteria:*** An acceptance criteria should be established for each of the parameters/indicators identified such that once the criteria is exceeded, corrective actions must be taken to refurbish or replace the component. ***(7) Corrective Actions:*** Based on the acceptance criteria established, corrective actions should be implemented to refurbish or replace components not meeting the minimum acceptance criteria. ***(8 & 9) Confirmation Process and Administrative controls:*** A process should be included to ensure that inspection results are reviewed and compared against acceptance criteria, and that corrective actions are implemented, when necessary. Appropriate administrative controls should be in place to ensure that the inspections are performed in a standardized manner and at the proper frequency, and that results are properly documented. ***(10) Operating experience:*** Past operating experience should be reviewed and evaluated to identify any plant specific aging issues that should be addressed for these components in the program.	No

VI. ELECTRICAL COMPONENTS
E. Electrical Insulators

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E.2.1	Strain and suspension insulator	Assembly	Porcelain, Galvanized Metals, Stainless Steel, Cement	High temperature, dirt, dust, salt, vibration, and humidity, wind	Leakage current, loss of function, cracking	Surface contamination or oxidation, loss of material due to wear, corrosion, mechanical stress, vibration	IN 93-95

F. Transmission Conductors

F.1 Conductor

F.1.1 Assembly

and distribution

VI. ELECTRICAL COMPONENTS
F. Transmission Conductors

Systems, Structures and Components

This review table addresses transmission conductors. Transmission conductors form an integral part of the utility transmission system connecting the power station to offsite power sources, and tying the main generator output to the utility's power grid.

System Interfaces

Transmission conductors functionally interface with the utility transmission system connecting the power station to offsite power sources, and tying the main generator output to the utility's power grid

VI. ELECTRICAL COMPONENTS
F. Transmission Conductors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
F.1.1	Transmission conductors	Assembly	Aluminum, Steel	High temperature, vibration, dirt, dust, salt, wind, ice, oxygen, and humidity	Leakage current, fatigue	Surface contamination or oxidation, corrosion, material loss due to wear fatigue	None

G. Ground Conductors

G.1 Conductor

G.1.1 Assembly

VI. ELECTRICAL COMPONENTS
G. Ground Conductors/~~Grid~~ Ground Grid.

Systems, Structures and Components

This review table addresses (ing) ground conductors. The electrical ground conductors make up the plant's electrical ground (ing) system. This system establishes the reference ground potential for electrical system voltages in the entire plant. Electric power system voltage measurements are referenced to the ground system, and all protective relaying, basic insulation levels, instrumentation, controls, and metering depend on the design integrity of the plant ground system. Personnel and equipment safety are also dependent on the ground (ing) system grid.

System Interfaces

Ground conductors functionally interface with all circuits that are electrically connected to ground.

VI. ELECTRICAL COMPONENTS
G. Ground Conductors

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
G.1.1	Ground conductor	Assembly	Copper, bronze	Humidity, salt, oxygen	Loss of function, increased electrical resistance	Surface contaminati on or oxidation, corrosion, mechanical stress	None

or Measurement of effective grounding impedance

VI. **ELECTRICAL COMPONENTS**
G. Ground Conductors

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Ground Conductor Inspection Program Physical Inspection of ground grid conductors may or may not be included in a plant preventive maintenance program. No generally accepted methods to monitor the integrity of cable ground conductors exist. Periodic visual inspection is one potential approach, however, the majority of the ground grid is inaccessible. Indirect indicators of ground integrity are provided through instrument calibration programs, periodic inspection, maintenance, and testing of protective relaying, and the monitoring of electric power system quality and operating parameters. While no requirement currently exists for such a program, periodic visual inspection of accessible ground conductors is a potential method of managing aging degradation for these components. The inspection program should check for indications of any of the identified aging mechanisms, such as corrosion. In addition, infrared thermography can be used to identify hot spots. Since the majority of the ground grid is inaccessible, indirect indicators of ground integrity should also be included. If no indications are found, this would provide some assurance that aging degradation is not adversely impacting the ability of the components to perform their intended function. If indications of aging degradation are noted, corrective actions can be taken prior to failure occurring.	As one potential means of managing aging of ground conductors, an inspection program can be implemented in which periodic visual inspections, along with indirect measurements of ground integrity are performed. The 10 criteria identified in the draft SRP-LR are discussed for such a program below: ***(1) Scope:*** The inspection program should include all ground conductors that are important to safety. ***(2) Preventive Actions:*** Any preventive actions that can be taken to mitigate aging degradation should be identified. ***(3) Parameter Monitored/Inspected:*** The parameters to be monitored/inspected should be determined based on the aging mechanisms identified as important for these components. Each of the aging mechanisms presented in this table should be addressed by identifying a parameter or indicator that can be observed during the inspection. ***(4) Detection:*** Each of the parameters/indicators should be observed during the inspection to provide some assurance that aging degradation is detected prior to failure. ***(5) Monitoring and Trending:*** Any aging indicators noted during the inspection should be quantified, to the extent possible, to allow trending in future inspections. ***(6) Acceptance Criteria:*** An acceptance criteria should be established for each of the parameters/indicators identified such that once the criteria is exceeded, corrective actions must be taken to refurbish or replace the component. ***(7) Corrective Actions:*** Based on the acceptance criteria established, corrective actions should be implemented to refurbish or replace components not meeting the minimum acceptance criteria. ***(8& 9) Confirmation Process and Administrative controls:*** A process should be included to ensure that inspection results are reviewed and compared against acceptance criteria, and that corrective actions are implemented, when necessary. Appropriate administrative controls should be in place to ensure that the inspections are performed in a standardized manner and at the proper frequency, and that results are properly documented. ***(10) Operating experience:*** Past operating experience should be reviewed and evaluated to identify any plant specific aging issues that should be addressed for these components in the program.	No

CHAPTER VII

(12/06/99)

AUXILIARY SYSTEMS

Major Plant Sections

- A1. New Fuel Storage
- A2. Spent Fuel Storage
- A3. Spent Fuel Pool Cooling and Cleanup (PWR)
- A4. Spent Fuel Pool Cooling and Cleanup (BWR)
- A5. Suppression Pool Cleanup System (BWR)
- B1. Light Load Handling Systems (Related to Refueling)
- B2. Overhead Heavy Load Handling Systems
- C1. Open Cycle Cooling Water System (Service Water System)
- C2. Closed Cycle Cooling Water System
- C3. Ultimate Heat Sink
- D. Compressed Air System
- E1. Chemical and Volume Control System (PWR)
- E2. Standby Liquid Control System (BWR)
- E3. Reactor Water Cleanup System (BWR)
- E4. Coolant Storage/Refueling Water System (PWR)
- E5. Shutdown Cooling System (Old BWR)
- F1. Control Room Area Ventilation System
- F2. Auxiliary and Radwaste Area Ventilation System
- F3. Primary Containment Heating and Ventilation System
- F4. Diesel Generator Building Ventilation System
- G. Fire Protection
- H1. Diesel Fuel Oil System
- H2. Emergency Diesel Generator System
- I. Liquid Waste Disposal System

A1. New Fuel Storage

A1 New Fuel Storage

A1.1 New Fuel Rack

A1.1.1 New Fuel Rack Assembly

A1. New Fuel Storage

System, Structures, and Components

The system, structures, and components included in this table comprise the new fuel storage which contains carbon steel new fuel storage racks located in the auxiliary building. The racks are exposed to temperature and humidity conditions of the auxiliary building. The racks are generally painted with protecting coating. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the new fuel storage are classified as Group C Quality Standards.

System Interfaces

No other systems contained in this report interface with the new fuel storage.

While PWR and BWRs are not explicitly mentioned, the term auxiliary building is mentioned implying PWRs. Were BWRs not examined because the BWR new fuel vaults generally have covers which my prevent moisture from getting to the new fuel racks?

VII AUXILIARY SYSTEMS

A1. NEW FUEL STORAGE

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A1.1.1	New Fuel Rack	New Fuel Rack Assembly	Carbon Steel	Indoors: Exposed to temperature and humidity conditions inside the Auxiliary Building	Loss of Material	General Corrosion, Coating Degrada-tion	Plant Technical Specifications.
A1.1.1	New Fuel Rack	New Fuel Rack Assembly	Carbon Steel	Indoors: exposed to temperature and humidity conditions inside the Auxiliary Building	Local Loss of Material	Pitting Corrosion and Crevice Corrosion, Coating Degrada-tion	Plant Technical Specifications.

While there is analysis done to show that fuel in these racks will not be physically able to go critical, there is also a requirement that (for PWRs) the floor drains be operable. If these drains are considered a passive component, then they should be considered.

A2. Spent Fuel Storage

A2.1 Spent Fuel Storage Rack

A2.1.1 Neutron-Absorbing Sheets

A2. Spent Fuel Storage

A2.1 Spent Fuel Storage Rack

A2.1.1 Neutron-Absorbing Sheets

In my judgement, there are other passive components associated with the spent fuel pool. These include inflatable seals and the stainless steel pool liner. Regarding the liner, pools generally have leak detection systems which provide a surveillance method for pool leakage. This may be adequate to provide indication of a leak in the liner. However, previous operating experience thru 1996 indicated evens involving small leaks (less than 50 gallons per day).

Regarding the inflatable seals in gates in both BWR and PWR pools, there was previous operating experience indicated problems with these seals. Mention of these seals may be appropriate if these are considered passive components.

A2. Spent Fuel Storage

System, Structures, and Components

The system, structures, and components included in this table comprise the pressurized water reactor (PWR) spent fuel storage. The PWR spent fuel storage contains stainless steel spent fuel storage racks and Boraflex sheets (if used) submerged in a chemically treated borated water. The intended function of the spent fuel rack is to separate spent fuel assemblies. Boraflex sheets fastened to the storage cells provide for neutron absorption and help maintain subcriticality of spent fuel assemblies in the spent fuel pool. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the spent fuel storage are classified as Group C Quality Standards.

System Interfaces

No other systems contained in this report interfaces with the PWR spent fuel storage.

BWRs have fixed poison in the spent fuel pools (SFPs) which, while not subject to degradation from borated water, is subject to irradiation degradation and, therefore has some aging susceptibility. There is no BWR spent fuel pool poison discussion. Consideration should be given to BWR SFPs as well.

Boraflex was not the only poison material containing boron used in reactor spent fuel pools. I found reference to boral also. Consideration should be given to mentioning them as well as boraflex.

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A2.1.1	Spent Fuel Storage Racks	Neutron-Absorbing Sheets	Boraflex	Immersed in Chemically Treated Borated Water	Loss of Boron Carbide Material; Reduction of Neutron-Absorbing Capacity: Gap Formation due to Shrinkage of Boraflex Panels	Boraflex Degrada-tion	EPRI NP-6159. EPRI TR-101926. EPRI TR-103300. Plant Technical Specifications. Operating Experience NRC IN 87-43. NRC IN 93-70. NRC IN 95-38. NRC GL 96-04.

The same words would seem applicable to BWRs as well.

These same words would seem appropriate for other poisons.

Technical Specifications (TS) are probably not universally used for boron control in the poison material although they do set an upper limit on fuel pool reactivity. Cursory TS review in the past did not indicate control of the poison material by TS other than by reactivity of fuel in the SFP. Is this what is meant by TS?

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Generally, a Boraflex monitoring program on the test coupons or the actual Boraflex panels, based on manufacturer's recommendations, should be implemented in the initial installation of the spent fuel racks to assure that no unexpected degradation of the Boraflex material would compromise the criticality analysis in support of the design of spent fuel storage racks. The applicable AMP, based on manufacturer's suggestion, is usually implemented by the plant technical specifications and relies on periodic inspection, testing, monitoring and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained. The frequency of the inspection and testing should be about every 4-5 years based on the manufacturer's recommendation for a 40-year service life for the spent fuel racks. The AMP should include: (1) Visual inspection of the physical conditions of the sampling coupons for detecting degradation of the Boraflex material, such as discoloration and reduction of thickness. (2) Performing neutron attenuation testing called "blackness testing" to determine gap formation in Boraflex panels. (3) Sampling and analysis for silica levels in the spent fuel pool water and trending the results using the RACKLIFE code. (4) Measuring boron areal density by the BADGER device. (5) Corrective actions should be initiated if the test results found that the 5% subcriticality margin cannot be maintained because of the current or projected future Boraflex degradation.	***(1) Scope of Program:*** The AMP should focus on managing the effects of Boraflex material degradation (i.e., loss of boron carbide neutron absorber due to gradual degradation of polymer matrix in the release of silica from Boraflex following gamma irradiation and long-term exposure to the wet pool environment) on the intended function of the spent fuel racks to prevent criticality. ***(2) Preventive Actions:*** Periodic visual inspection of sampling coupons prevents unexpected degradation of the Boraflex material. ***(3) Parameters Monitored/Inspected:*** The parameters monitored should include physical conditions of the sample coupons such as thickness, discoloration, and hardness, which are conditions directly related degradation of the Boraflex material. Operating experience has shown that the degraded surfaces of the test coupons have a gray discoloration. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the ply siloxane polymer matrix becomes degraded and silica filler and boron carbide are released. NRC Information Notice (IN) 95-38 indicated that the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of the silica from the surface of the Boraflex and a gradual thinning of the material. Visual inspection should be used to detect Boraflex degradation such as discoloration and reduction of thickness. In addition gap formation and decrease of areal boron density should be monitored. ***(4) Detection of Aging Effects:*** Because Boraflex contains about 25 percent silica, 25 percent polydimethyl soloxane polymer, and 50 percent boron carbide, sampling and analysis the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex. The amount of boron carbide released from Boraflex should be correlated to the levels of silica present in the spent fuel pool. This is supplemented by direct measurement of boron loss using BADGER device. ***(5) Monitoring and Trending:*** The periodic inspection measurements and analysis should provide data for trending. ***(6) Acceptance Criteria:*** The 5% subcriticality margin of the spent fuel racks must be maintained for the period of license renewal. ***(7) Corrective Actions:*** Corrective actions should be initiated if the test results found that the 5% subcriticality margin cannot be maintained because of the current or projected future Boraflex degradation. These corrective actions may consist of providing additional neutron absorbing capacity by borated steel inserts. ***(8-9) Confirmation Process, and Administrative Controls:*** Site QA procedures, site review and approval process, and administrative controls are implemented in accordance with Appendix B to 10 CFR Part 50 requirements and will continue to be adequate for license renewal. ***(10) Operating Experience:***	Yes, no generic AMP

OK

VII AUXILIARY SYSTEMS

A2. SPENT FUEL STORAGE

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References

A3. Spent Fuel Pool Cooling and Cleanup (Pressurized Water Reactor)

A3.1 Piping

A3.1.1 Pipe, Fittings and Flanges

A3.1.2 Studs and Nuts

A3.2 Filter

A3.2.1 Studs and Nuts

A3.3 Strainer

A3.3.1 Studs and Nuts

A3.4 Check Valve

A3.4.1 Body and Bonnet

A3.4.2 Studs and Nuts

A3.5 Hand Valve

A3.5.1 Body and Bonnet

A3.5.2 Studs and Nuts

A3.5.3 Linings

A3.6 Heat Exchanger

A3.6.1 Shell

A3.6.2 Nozzles

A3.6.3 Studs and Nuts

A3.7 Ion Exchanger

A3.7.1 Studs and Nuts

A3.8 Pump

A3.8.1 Casing

A3.8.2 Studs and Nuts

A3.9 Flow Orifice

A3.9.1 Studs and Nuts

A3.10 Spent Fuel Transfer Tube

A3.10.1 Studs and Nuts

A3. Spent Fuel Pool Cooling and Cleanup (Pressurized Water Reactor)

System, Structures, and Components

The system, structures, and components included in this table comprise the pressurized water reactor (PWR) spent fuel storage. The PWR spent fuel storage contains stainless steel spent fuel storage racks and Boraflex sheets (if used) submerged in a chemically treated borated water. The intended function of the spent fuel rack is to separate spent fuel assemblies. Boraflex sheets fastened to the storage cells provide for neutron absorption and help maintain subcriticality of spent fuel assemblies in the spent fuel pool. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the spent fuel storage are classified as Group C Quality Standards.

System Interfaces

No other systems contained in this report interfaces with the PWR spent fuel storage.

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A3.1.1	Piping	Pipe, Fittings, and Flanges	Stainless Steel (SS)	Chemically Treated Borated Water	Local Loss of Material	Pitting and Crevice Corrosion	ASME Section XI, 1989 Edition. NRC IN 84-18. NRC IN 96-11. NRC GL 88-05 EPRI TR-105714. Plant Technical Specifications.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
The AMP relies on minimizing impurities by monitoring and maintaining the borated water chemistry in accordance with the guidelines of EPRI TR-105714 and implemented by plant technical specifications, and inservice inspection (ISI) is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWD 2500-1, test and examination category D-C for systems in support of residual heat removal from spent fuel storage pool.	***(1) Scope of Program:*** The AMP relies on monitoring and maintaining the water chemistry and inservice inspection (ISI) for managing the effects of pitting and crevice corrosion on the intended function of the spent fuel pool cooling and cleanup system components. ***(2) Preventive Actions:*** Monitoring and maintaining the system water chemistry in accordance with the guidelines of EPRI TR-105714 helps to minimize impurities in the system fluid. The AMP generally contains chemical parameter specifications, sampling frequency, analysis, and corrective actions. Chemical parameters, such as concentrations of chloride, sulfate, oxygen, and impurities are monitored and controlled. The preventive actions, however, are considered inadequate because of inadvertent introduction of impurities into the system due to unacceptable levels of contaminants in the boric acid, exposure of the spent fuel pool free surface to airborne contaminants (IN 84-18), or from ingress of demineralizer resins (IN 96-11). ***(3) Parameters Monitored/Inspected:*** The system water chemistry is monitored and controlled to mitigate the effects of pitting and crevice corrosion on the intended function of the component. Examination category D-C of ASME Section XI Table IWD 2500-1 requires visual VT-2 examination during system leakage and hydrostatic test. ***(4) Detection of Aging Effects:*** Within the spent fuel pool cooling system there are regions of low and stagnant flow conditions where impurities and/or corrosive chemicals may concentrate and cause crevice and pitting corrosion. VT-2 examination of ASME Section XI, Table IWD 2500-1 will not detect pitting and crevice corrosion. Therefore, a one-time inspection of representative components and susceptible locations should be undertaken to ensure that significant corrosion is not occurring. Based on piping/component geometry and fluid flow conditions, susceptible locations can be identified. Follow up actions are based on the inspection results and plant technical specification. ***(5) Monitoring and Trending:*** The results of periodic monitoring of borated water chemistry provide data for trending. The results of the one-time inspection should be used to dictate future inspection. System leakage test is conducted prior to plant startup following each refueling outage and hydrostatic test at or near the end of each inspection interval. ***(6) Acceptance Criteria:*** The chemistry monitoring program provides specification of chemical parameters and acceptable levels. Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWD-3000. ***(7) Corrective Actions:*** Plant borated water chemistry control program specifies the target values for the chemistry parameters. Corrective actions are taken if the target values are exceeded. Corrective actions of the above one-time inspection are based on the results of the inspection. Furthermore, IWA-5250 requires that the source of leakage detected during the pressure test should be located and evaluated for corrective measures. Repair and replacement are in accordance with IWA-4000 and	Yes, Element 4 should be further evaluated

Are TS universally used to control SFP water chem? I'm not familiar with them.

Selection is important if only a "one time" inspection is to be done.

VII AUXILIARY SYSTEMS

A3. SPENT FUEL POOL COOLING AND CLEANUP (Pressurized Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
A3.1.1	Piping	Pipe, Fittings, and Flanges	Carbon Steel (CS)	Chemically Treated Borated Water	Loss of Material	General, Pitting and Crevice Corrosion	ASME Section XI, 1989 Edition. NRC IN 84-18. NRC IN 96-11. EPRI TR-105714. NRC GL 88-05. Plant Technical Specifications.
A3.1.1	Piping	Pipe, Fittings, and Flanges	SS	Chemically Treated Borated Water	Crack Initiation and Growth	Stress Corrosion Cracking (SCC)	ASME Section XI, 1989 Edition. Regulatory Guide 1.44. NRC IN 84-18. NRC GL 88-05. NRC IN 97-19. EPRI TR-105714. Plant Technical Specifications.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Long-term exposure of the rubber linings to borated water can result in rubber degradation such as, welling, hardening and cracking which, in turn, can cause corrosion of the underlying carbon steel surfaces. No existing aging management program.	An inspection program should be implemented to manage the effects of rubber degradation on the intended function of the component. The program should include sampling criteria, inspection method, inspection frequency, acceptance criteria, and corrective action. Plant specific aging management program is to be evaluated.	Yes, no existing AMP
The AMP relies on minimizing impurities by monitoring and maintaining reactor coolant and cooling water chemistry implemented by plant technical specifications, and inservice inspection (ISI) in conformance with ASME Section XI (edition specified in 10 CFR 50.55a). Table IWD 2500-1, test and examination category D-C for systems in support of residual heat removal from spent fuel storage pool.	***(1) Scope of Program:*** The program relies on monitoring and maintaining reactor coolant and cooling water chemistry and inservice inspection (ISI) for managing the effects of pitting and crevice corrosion on the intended function of the component. ***(2) Preventive Actions:*** Monitoring and maintaining the chemistry conditions of reactor coolant and cooling water will minimize the impurities in the system fluid. The preventive actions, however, are considered inadequate because of inadvertent introduction of impurities into the system. Also, high concentration of impurities at locations having stagnant flow could cause pitting and crevice corrosion. ***(3) Parameters Monitored/Inspected:*** The parameters monitored in the borated water are provided in the specifications based on EPRI guidelines. The parameters include dissolved iron, dissolved copper, chlorides, dissolved oxygen, suspended solids, pH, and hydrazine. Examination category D-C of ASME Section XI Table IWD 2500-1 requires visual VT-2 examination during system leakage test and system hydrostatic test to detect the leakage. ***(4) Detection of Aging Effects:*** Within the spent fuel pool cooling system, there are regions of low and stagnant flow conditions where impurities and/or corrosive chemicals may concentrate and cause pitting and crevice corrosion. Visual examination VT-2 required by IWD 2500-1 will not detect pitting and crevice corrosion. Therefore, a one-time inspection of representative components and susceptible locations should be undertaken to ensure that significant corrosion is not occurring. Based on piping/component geometry and fluid flow conditions, susceptible locations can be identified. Follow up actions are based on inspection results and plant technical specification. ***(5) Monitoring and Trending:*** The results of periodic monitoring of borated water chemistry provide data for trending. The results of the one-time inspection should be used to dictate future inspection. System leakage test is conducted prior to plant startup following each refueling outage, and hydrostatic test at or near the end of each inspection interval. ***(6) Acceptance Criteria:*** The chemistry monitoring program provides specification of chemical parameters and acceptable levels. Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with acceptance standards of IWD-3000 for Class 3 components. ***(7) Corrective Actions:*** Plant borated water chemistry control program specifies the target values for the chemistry parameters. Corrective actions are taken if the target values are exceeded. Corrective actions of the above one-time inspection are based on the results of the	Yes, Element 4 should be further evaluated

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A3.6.1 thru A3.6.3	Heat Exchanger	Shell, Nozzles (external surface), Studs and Nuts	CS, LAS	Air, leaking Chemically Treated Borated Water	Loss of Material	Boric Acid Corrosion	NRC GL 88-05.
A3.7.1	Ion Exchanger	Studs and Nuts	CS, LAS	Air, leaking Chemically Treated Borated Water	Loss of Material	Boric Acid Corrosion	NRC GL 88-05.
A3.8.1	Pump	Casing	SS, CS with SS Cladding	Chemically Treated Borated Water	Loss of Material	Pitting and Crevice Corrosion, Cavitation Erosion	ASME Section XI, 1989 Edition. ASME OM Code-1990, Subsection ISTB. NRC GL 89-04. NRC IN 84-18. NRC IN 96-11. EPRI TR 105714. Plant Technical Specifications.

The pump vent pipe has a history of a few problems. Should it be mentioned explicitly?

A4. Spent Fuel Pool Cooling and Cleanup (Boiling Water Reactor)

A4.1 Piping

A4.1.1 Pipe, Fittings and Flanges

A4.2 Valves

A4.2.1 Body and Bonnet

A4.3 Heat Exchanger

A4.3.1 Shell

A4.4 Pump

A4.4.1 Casing

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur.	
The AMP relies on minimizing impurities by monitoring and maintaining the system water chemistry implemented by plant technical specifications, and inservice inspection (ISI) is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWD 2500-1, test and examination category D-C for systems in support of residual heat removal from spent fuel storage pool.	***(1) Scope of Program:*** The program relies on monitoring and maintaining the chemistry conditions of the system water for managing the effects of pitting and crevice corrosion on the intended function of the component. ***(2) Preventive Actions:*** Monitoring and maintaining the system water chemistry in accordance with the guidelines of NUREG 0313, Rev. 2 and EPRI guidelines specified in TR-103515 minimize the impurities in the system fluid. Parameters directly related to corrosion, such as concentrations of chloride, sulfate, oxygen, and impurities are monitored and controlled. ***(3) Parameters Monitored/I inspected:*** The parameters monitored include dissolved iron, dissolved copper, chlorides, dissolved oxygen, suspended solids, pH, and hydrazine. Dissolved iron and copper are parameters directly related to corrosion. Examination category D-B of ASME Section XI Table IWD 2500-1 requires visual VT-2 examination during system leakage test and system hydrostatic test to detect the leakage. However, high concentration of impurities at locations having stagnant flow could cause pitting and crevice corrosion. ***(4) Detection of Aging Effects:*** Visual examination VT-2 required by IWD 2500-1 can detect and identify the leakage, but can not detect pitting and crevice corrosion. Therefore, inspection at susceptible locations should be undertaken to ensure that significant corrosion is not occurring. ***5) Monitoring and Trending:*** The frequency of monitoring system water chemistry ranges from several times per week to once a month. The results of monitoring should provide data for trending. ***(6) Acceptance Criteria:*** The chemistry monitoring program provides chemical parameter specification and acceptable levels. Any significant degradation is reported and requires further evaluation. ***(7) Corrective Actions:*** The AMP contains chemical parameter specifications, sampling frequency, analysis and corrective actions. If the specified values are exceeded, corrective actions are initiated to bring back the chemistry parameters to specified levels. ***(8 & 9) Confirmation Process, and Administrative Controls:*** Site corrective actions program, QA procedures, site review and approval process, and administrative controls are implemented in accordance with Appendix B to 10 CFR Part 50 requirements and will continue to be adequate for license renewal. ***(10) Operating Experience:*** Corrosion and pitting can occur at the crevices that are not exposed to the general flow stream or under stagnant flow conditions, such as at the tubesheet-shell joint, and other crevices in the shell side of heat exchanger.	Yes, Element 4 should be further evaluated

VII AUXILIARY SYSTEMS
A4. SPENT FUEL POOL COOLING AND CLEANUP (Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A4.4.1	Pump	Casing	SS, CS with SS Cladding	Oxygenated Water at Temperature up to 51°C (125°F)	Loss of Material	Pitting and Crevice Corrosion	ASME Section XI, 1989 Edition. ASME OM Code–1990, Subsection ISTB. NUREG-0313 Rev. 2. NRC GL 89-04. Plant Technical Specifications. EPRI TR-103515

THE ANTISIPHON DEVICE ~~[illegible]~~ should BE MENTIONED - FOR BWRs. SOMETIMES a CHECK valve - MENTIONED FOR PWRs - WHY NOT here?

B1. Light Load Handling Systems (Related to Refueling)

B1.1 Bridge (for cranes that fall within the scope of 10 CFR 54)

B1.1.1 Structural Girders

B1.2 Rail System

B1.2.1 Frame Cut Holes

B1.2.2 Rail

Jit:

General comments:

Format question: The only difference between the "B1" (Light Load) section and the "B2" (Heavy Load) section is added reference to NUREG-0612 for the "Structural Girders - Loss of Materials" row. Things could be greatly simplified. Too much redundancy.

The following additions should be considered:

Item B1.1.1 Structural Girders (aging effect; cumulative fatigue damage)

The aging mechanism of fatigue in the "Structural Girders" would most likely be manifest in cracking of the truck flanges, truck web and girder web on both sides at each corner of the crane. These would be normal stress points.

Suggest including a visual inspection for cracking in the above areas.

Item B1.1.1 Structural Girders (aging effect; loss of material)

As stated in the "Evaluation and Technical Basis" section, "There has been no history in the nuclear industry of corrosion related degradation that has impaired crane girders from meeting their structural and functional requirements." It would appear that all that is needed is the inspection criteria in ASME B30.2 that relates to passive components. The current draft appears to be excessive.

Item B1.2.1 Rail System - Frame Cut Holes (aging effect; cumulative fatigue damage)

I'm not sure why this item is listed. I assume that this item refers to the rail supports. Why not group this item with B1.1.1 under fatigue?

Item B1.2.2 Rail (aging effect; attrition)

The "Evaluation and Technical Basis" section draft also appears to be excessive. The two main areas for consideration should be the alignment of the rails, and the potential for bolts to become loose. Alignment checking and bolt torque checking should resolve most rail problems. The existence of a crane surveillance by the licensee and adequate corrective actions to address any deficiencies, should be sufficient.

Item B2.1.1 Structural Girders (aging effect; cumulative fatigue damage)

Same comment stated for Item B1.1.1.

Item B2.1.1 Structural Girders (aging effect; loss of material)

Same comment stated for Item B1.1.1.

Item B2.2.1 Rail System - Frame Cut Holes (aging effect; cumulative fatigue damage)

Same comment stated for Item B1.2.1.

Item B2.2.2 Rail (aging effect; attrition)

Same comment stated for Item B1.2.2.

B2. Overhead Heavy Load Handling System

B2.1 Bridge (for cranes that fall within the scope of 10 CFR 54)

B2.1.1 Structural Girders

B2.2 Rail System

B2.2.1 Frame Cut Holes

B2.2.2 Rail

C1. Open Cycle Cooling Water System (Service Water system)

C1.1 Piping

C1.1.1 Piping and Fittings

C1.1.2 Underground Piping and Fittings

C1.2 Valves

C1.2.1 Body and Bonnet

C1.3 Heat Exchanger

C1.3.1 Shell

C1.3.2 Channel

C1.3.3 Channel Head

C1.3.4 Tube Sheets

C1.3.5 Tubes

C1.4 Flow Orifice

C1.4.1 Body

C1.5 Pump

C1.5.1 Casing

C1.6 Basket Strainer

C1.6.1 Body

C1. Open Cycle Cooling Water System (Service Water System)

System, Structures, and Components

The system, structures, and components included in this table comprise the open cycle cooling water system which consists of piping, valves, heat exchangers, pumps, flow orifices, and basket strainers. The system contains raw untreated salt or fresh water. The system removes heat from the closed cycle cooling water system and, in some plants, other auxiliary systems and components such as steam turbine bearing oil coolers, or miscellaneous coolers in the condensate system. The heat is absorbed by the ultimate heat sink such as a cooling pond, cooling tower, river, lake, or sea. This table only addresses the heat exchangers for removing heat from the closed cycle cooling system; heat exchangers for removing heat from other auxiliary systems and components are addressed in their respective systems, such as Table VIII A for steam turbine bearing oil coolers and Table VIII E for condensate system coolers. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the open cycle cooling water system are classified as Group C Quality Standards.

Pumps and valves Internals are considered to be active components and pump internals and seats, discs, bolting, and other valve items should be covered by the plant maintenance program.

System Interfaces

The systems that interface with the open cycle cooling water system include the closed cycle cooling water system (Table VII C2), ultimate heat sink (Table VII C3), and other miscellaneous auxiliary systems and components.

1 Low flow cavitation of pump casing; IN 89-08 and BL 88-04 address low flow pump cavitation. The Service Water pumps (submersible pumps) at Susquehanna plant have experienced severely cavitation-induced damage of pump casings in 1986. The low-flow issue was not adequately addressed by all plants. This may be, in part, due to the lack of a generic guideline for determining the acceptance of a pump for operation under the various modes and times required in support of both normal and emergency conditions.

VII AUXILIARY SYSTEMS

C1. OPEN CYCLE COOLING WATER SYSTEM (Service Water System)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
C1.1.1	Piping	Piping and Fittings (with or without Internal Lining or Coating)	Brass, Copper-Nickel, ALUMINUM BRONZE, Carbon Steel (for fresh water only)	Raw, Untreated Salt Water or Fresh Water	Loss of Material	General, DEALLOYING (OF ALUMINUM BRONZE), Micro-biologically-Induced, Pitting, and Crevice Corrosion.	ASME Section XI, 1989 Edition. NRC IN 94-03. GL 89-13.

VII AUXILIARY SYSTEMS

C1. OPEN CYCLE COOLING WATER SYSTEM (Service Water System)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
C1.2.1	Valves (Check, Hand, & Control Valves)	Body and Bonnet (with or without Internal Lining or Coating) ALUMINUM BRONZE	Bronze, Stainless Steel, Carbon Steel (for fresh water only)	Raw, Untreated Salt Water or Fresh Water	Loss of Material	General, Micro-biologically -Induced, Pitting, and Crevice Corrosion. DEALLOYING (OF ALUMINUM BRONZE)	ASME Section XI, 1989 Edition. NRC IN 94-03. Plant Technical Specifications. GL 89-13.

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
C1.3.1 thru C1.3.5	Heat Exchanger (between open cycle and closed cycle cooling water systems)	Shell, Channel, Channel Head, Tube Sheet, Tubes	Shell, Channel, Channel Head: Carbon Steel; Tube sheet: Aluminum-Bronze; Tubes: Copper-Nickel	Shell Side: Treated Water; Tube Side: Raw Untreated Salt or Fresh Water	Loss of Material	DEALLOYING (OF ALUMINUM BRONZE) General, Microbio-logically-Influenced, Pitting, and Crevice Corrosion	NRC GL 89-13. Plant Technical Specifications. *Operating Experience* NRC IN 81-21. NRC IN 85-24. NRC IN 85-30. NRC IN 86-96. NRC IN 94-03.

C2. Closed Cycle Cooling Water System

C2.1 Piping

C2.1.1 Pipe, Fittings, and Flanges

C2.2 Valves (Check, Hand, Control, Relief, and Solenoid Valves)

C2.3.1 Body and Bonnet

C2.3 Pump

C2.3.1 Casing

C2.4 Tank

C2.4.1 Shell

C2.5 Flow Orifice

C2.5.1 Body

C2. Closed Cycle Cooling Water System

System, Structures, and Components

The system, structures, and components included in this table comprise the closed cycle cooling water system which consists of piping, valves, radiation element, temperature element, heat exchangers, pumps, tank, and flow orifices. The system contains chemically treated demineralized water. The closed cycle cooling water system is designed to remove heat from various auxiliary systems and components such as chemical and volume control system, spent fuel cooling system, etc. The open cycle cooling water system (Table VII C1) provides the cooling medium for the heat exchangers of the closed cycle cooling water system which serves as an intermediate barrier between the various supplied auxiliary systems and the open cycle cooling water system. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the closed cycle cooling water system are classified as Group C Quality Standards.

The AMPs of the heat exchanger between the closed cycle and the open cycle cooling water systems are addressed in the open cycle cooling water system (Table VII C1). The AMPs of the heat exchangers between the closed cycle cooling water system and the interfacing auxiliary systems are included in their respective systems, such as Table VII A.3 for PWR spent fuel cooling water system, Table VII A4 for BWR spent fuel pool cooling and cleanup system, and Table VII E1 for chemical and volume control system.

Pumps and valves internals are considered to be active components and pump internals and seats, discs, bolting, and other valve items should be covered by the plant maintenance program.

System Interfaces

The systems that interface with the closed cycle cooling water system include the open cycle cooling water system (Table VII C1), PWR spent fuel cooling water system (Table VII A3), BWR spent fuel cooling water system (Table VII A4), chemical and volume control system (Table VII E1), and other miscellaneous auxiliary systems and components.

VII AUXILIARY SYSTEMS

C2. CLOSED CYCLE COOLING WATER SYSTEM

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
C2.1.1	Piping	Pipe, Fittings, and Flanges	Carbon Steel (CS)	35°C Chemically Treated De-mineralized Water	Local Loss of Material	General, Pitting, and Crevice Corrosion	ASME Section XI, 1989 Edition. Plant Technical Specifications.
	Piping	Pipe, Fittings	Carbon St'l	Chemically treated Demineralized Water	Wall thinning	Erosion/Corrosion	NRC IN 86-106 and S 1, 2, & 3. NRC IEB 87-01 NRC GL 89-08 NRC IN 87-36 IN 88-17

C3. Ultimate Heat Sink

C3.1 Cooling Tower

C3.1.1 Foundation

C3.1.2 Exterior Concrete Above Grade

C3.1.3 Exterior Concrete Below Grade

C3.1.4 Interior Slabs

C3.1.5 Masonry Block Wall

C3.1.6 Concrete Surfaces Exposed to Flowing Water

C3.1.7 Columns

C3.1.8 Base Plates

C3.1.9 Beams

C3.1.10 Trusses

C3.1.11 Bracings

C3.2 Piping

C3.2.1 Piping and Fittings

C3.3 Valves (Check, Hand, and Control Valves)

C3.3.1 Body and Bonnet

C3.4 Pump

C3.4.1 Casing

C3. Ultimate Heat Sink

System, Structures, and Components

The ultimate heat sink consists of a lake, ocean, river, ~~spray~~ pond, or cooling tower and provides sufficient cooling water for safe reactor shutdown and reactor cooldown via the residual heat removal system or other similar system. Due to the varying configurations of connections to lakes, oceans, and rivers, a plant specific aging management program is required. With respect to spray ponds, the spray modules should be covered by the plant maintenance program, and a plant specific aging management program is also required for the spray pond as an entity. Therefore, this table only addresses cooling towers.

The systems, structures and components included in this table consist of piping, valves, pumps, and concrete and steel components such as concrete walls, slabs, foundation, steel beams, columns, and base plates. The cooling tower contains raw or slightly treated fresh water. The ultimate heat sink absorbs heat from the open cycle cooling water system. The cooling tower is classified as Class 1 structures and other components such as piping and valves as Class 3.

Pumps and valves are considered to be active components and pump internals and seats, discs, and other valve items should be covered by the plant maintenance program.

System Interfaces

The systems that interface with the ultimate heat sink include the open cycled cooling water system (Table VII C1), containment spray system (Table V A), and emergency core cooling systems (Tables V D1 and D2).

Some general comments for consideration as appropriate

Aging management programs as applicable shall be provided for (1) trending deterioration of earthen dams and impoundments, including those that are cement stabilized; (2) trending and projecting silting and the rate of silt deposition since the original data was obtained; (3) trending and projecting meteorological, climatological, and oceanic data since the original data used in the FSAR was obtained, such as rain water run off for ponds and maximum and minimum temperatures, and controlling their affect on the UHS design basis, (4) trending and projecting existing and new aquatic flora and fauna concentrations and controlling their affect on the UHS design basis; (5) for plants located on rivers, trending maximum and minimum river stages and their affect on the UHS design basis; and (6) monitoring of aging degradation of all upstream and downstream dams affecting the UHS. When not specifically addressed or defined in USARs, plants shall have a defined and documented UHS design basis as part of their aging management program.

D. Compressed Air System

D.1 Piping

D.1.1 Piping and Fittings

D.2 Air Accumulator

D.2.1 Shell

D.2.2 Manway

D.2.3 Manway Bolting

D.3 Valves

D.3.1 Body and Bonnet

D.4 Filter

D.4.1 Shell

D.4.2 Manway

D.4.3 Manway Bolting

Harold Ornstein

D. Compressed Air System

D.1 Piping

D.1.1 Piping and Fittings

D.2 Air Accumulator

D.2.1 Shell

D.2.2 Manway

D.2.3 Manway Bolting

D.2.4 Check valve

D.3 Valves

D.3.1 Body and Bonnet

D.4 Filter

D.4.1 Shell

D.4.2 Manway

D.4.3 Manway Bolting

D.4.4 Filter media

D 5 Dryer

Columns

Valves

Drying media (desiccant)

D 6 Pressure Regulators

Jit where do Sensors for moisture monitors go?

Hal

D. Compressed Air system

System, Structures, and Components

The system, structures, and components included in this table comprise the compressed air system which consists of piping, valves, air accumulators and filters. The components normally contain very dry air, free of oil, water, and other contaminants. The system components and piping are located in various buildings at most nuclear power plants. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the compressed air system are classified as Group C Quality Standards.

Valves are considered to be active components and seats, discs, bolting, and other valve items should be covered by the plant maintenance program.

System Interfaces

No other systems contained in this report interface with the compressed air system.

No - should be Always
this is the root of the problem

however their cleanliness and the high quality of the air must be assured because it acts as the motive power for active (some safety related) components - which may not function properly because of contamination from the non-safety - Group of equipment

VII AUXILIARY SYSTEMS

D. COMPRESSED AIR SYSTEM

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
D.1.1	Piping	Piping and Fittings	Carbon Steel (CS) and Alloy Steel	Internal: Dry, Oil-Free Air; Occasionally Exposure to Moist Air. External: Room Air	Loss of Material	General and Pitting Corrosion	NRC IN 81-38. NRC IN 87-28. NRC IN 87-28 S1. NRC GL 88-14. INPO SOER 88-01. ASME OM Guide Part 17. ISA-S7.0.01-1996 EPRI/NMAC NP-7079
D.2.1 thru D.2.3	Air Accumulator	Shell, Manway, Manway Bolting. Check valves as part of accumulator.	CS	Internal: Dry, Oil-free Air. Occasionally Exposure to Moist Air. External: Room Air	Loss of Material	General and Pitting Corrosion	NRC IN 81-38. NRC IN 87-28. NRC IN 87-28 S1. NRC GL 88-14. INPO SOER 88-01. ASME OM Guide Part 17.
D.3.1	Valves	Body and Bonnet. diaphragms gaskets springs	CS	Internal: Dry, Oil-free Air. Occasionally Exposure to Moist Air. External: Room Air	Loss of Material	General and Pitting Corrosion	NRC IN 81-38. NRC IN 87-28. NRC IN 87-28 S1. NRC GL 88-14. INPO SOER 88-01. ASME OM Guide Part 17.

Also SOVs which control or are pieceparts of the AOVs diaphragms gaskets springs coils etc

OM 17 and ISA S7.0.01-1996 address air quality of moisture monitoring — a critical issue

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
The aging management program (AMP), based on NRC Generic Letter (GL) 88-14 and INPO's Significant Operating Experience Report (SOER) 88-01, relies on improved system inspections, maintenance, and testing, and generally includes: (1) frequent leak testing of valves, piping, and other system components, especially those made of carbon steel, and (2) preventative maintenance program which checks air quality at several locations in the system to address various aspects of the inoperability of air-operated components due to the presence of oil, water, rust, and other contaminants. Corrective actions are taken if any parameters are out of acceptable ranges, such as moisture content in the system air. The ASME Operation and Maintenance (OM) Guide Part 17, Performance Testing of Instrument Air System in Light-Water Reactor Power Plants, February 12, 1999 could be used as guidance for testing of air systems. But OM-17 also addresses air quality a critical item - similarly ISA std	***1) Scope of Program:*** The program relies on improved system inspection and maintenance program to manage the effects of corrosion on the intended function of the compressed air system. ***(2) Preventive Actions:*** The system air quality is monitored and maintained in accordance with manufacturer's recommendations for individual components served. ***(3) Parameter Monitored/ Inspected:*** Based on the guidelines of NRC Generic Letter (GL) 88-14 perform inservice testing to verify proper air quality, and that maintenance practices, emergency procedures, and training are adequate to ensure that the intended function of the air system is maintained. ***(4) Detection of Aging Effects:*** Degradation of the piping would become evident by observation of unacceptable leakage rates. However, inspection of representative components and susceptible locations should be undertaken to provide additional assurance that significant corrosion is not occurring. Based on piping or component geometry and flow conditions, susceptible locations can be identified. ***(5) Monitoring and Trending:*** Effects of corrosion are detectable by periodic local leak rate tests that also provide for timely detection of aging effects based on operating experience. ***(6) Acceptance Criteria*** The testing results are used to verify that the design and performance of the entire air system is in accordance with its intended function. ***(7-9) Corrective Actions, Confirmation Process, and Administrative Controls:*** Site corrective actions program, QA procedures, site review and approval process, and administrative controls are implemented in accordance with Appendix B to 10 CFR Part 50 requirements and will continue to be adequate for license renewal. ***(10) Operating Experience:*** Potentially significant problems pertaining to air systems have been documented in NRC Information Notices (INs) 87-28 and 87-28 S1. Some of the systems that have been significantly degraded or have failed include decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal system.	Yes, Element 4 should be further evaluated.
Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.	*Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.*	Yes, Element 4 should be further evaluated.
Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.	*Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.*	Yes, Element 4 should be further evaluated.

S7.0.01-1996 prescribes air quality

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
D.4.1 thru D.4.3	Filter	Shell, Manway, Manway Bolting	CS	Internal: Normally Dry, Oil-free Air. Occa-sionally Exposure to Moist Air. External: Room Air	Loss of Material	General and Pitting Corrosion	NRC IN 81-38. NRC IN 87-28. NRC IN 87-28 S1. NRC GL 88-14. INPO SOER 88-01. ASME OM Guide Part 17. ISA S7.0.01-1996

should add
Dryers – critical for operation of air system
Pressure Regulators – " " " " "

VII AUXILIARY SYSTEMS

D. COMPRESSED AIR SYSTEM

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.	*Same as the effects of General and Pitting Corrosion on Item D.1.1 piping and fittings.*	Yes, Element 4 should be further evaluated.

E1. Chemical and Volume Control System (Pressurized Water Reactor)

- E1.1 Piping (1500 psig rating)
    - E1.1.1 Pipe, Fittings and Flanges
    - E1.1.2 Stud and Nuts
- E1.2 Piping (150 psig rating)
    - E1.2.1 Pipe, Fittings and Flanges
    - E1.2.2 Studs and Nuts
- E1.3 High-Pressure Valve
    - E1.3.1 Body and Bonnet
    - E1.3.2 Studs and Nuts
- E1.4 Low-Pressure Valve
    - E1.4.1 Body and Bonnet
    - E1.4.2 Studs and Nuts
- E1.5 High-Pressure Pump
    - E1.5.1 Casing
    - E1.5.2 Closure Bolting
- E1.6 Low-Pressure Pump
    - E1.6.1 Casing
    - E1.6.2 Closure Bolting
- E1.7 Letdown Heat Exchanger
    - E1.7.1 Tube/Tubesheet
    - E1.7.2 Studs and Nuts
    - E1.7.3 Channel/Cover
    - E1.7.4 Channel/Welds

E1.7.5 Shell

E1.8 Regenerator Heat Exchanger

E1.8.1 Tube/Tubesheet

E1.8.2 Studs and Nuts

E1.8.3 Channel/Cover

E1.8.4 Channel/Welds

E1.8.5 Shell

E1.9 Basket Strainers

E1.9.1 Studs and Nuts

E1.10 Tank

E1.10.1 Studs and Nuts

E1.10.2 Shell

E1.10.3 Manway

E1.10.4 Penetrations/Nozzles

E2. Standby Liquid Control System (Boiling Water Reactor)

E2.1 Piping

E2.2 Solution Storage Tank

E2.3 Solution Storage Tank Heaters

E2.4 Pump Suction Valves

E2.5 Injection Pumps

E2.6 Relief Valves

E2.7 Injection Valves

E2.8 Containment Isolation Valves

E2.9 Injection Sparger

E2.10 Pump Suction Valves

E2. Standby Liquid Control System (Boiling Water Reactor)

E2.1 Piping

E2.2 Solution Storage Tank

E2.3 Solution Storage Tank Heaters

E2.4 Pump Suction Valves

E2.5 Injection Pumps

E2.6 Relief Valves

E2.7 Injection Valves

E2.8 Containment Isolation Valves

E2.9 Injection Sparger

E2.10 Pump Suction Valves —

This Subsection is a duplication of Subsection E2.4.

E2. Standby Liquid Control System (Boiling Water Reactor)

System, Structures, and Components

The system, structures, and components included in this table comprise the standby liquid control system, which serves as a backup reactivity control system in all boiling water reactors (BWRs) in the U.S. The major components of this system are the piping, solution storage tank, solution storage tank heaters, pump suction valves, injection pumps, relief valves, injection valves, containment isolation valves, injection sparger, and ~~pump suction valves~~. All of these components operate in contact with a Na pentaborate solution and are fabricated of austenitic stainless steel. Based on U.S. Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the standby liquid control system are classified as Group B Quality Standards.

Pumps and valves are considered to be active components; seats, discs, and other valve and pump internals should be covered by the plant maintenance program.

System Interfaces

The system that interfaces with the standby liquid control system is the BWR reactor pressure vessel (Table IV.A1). If used, the standby liquid control system would inject sodium pentaborate solution into the pressure vessel near the bottom of the reactor core.

E3. Reactor Water Cleanup System

E3.1 Piping

E3.1.1 Pipe and Fittings (beyond isolation valves)

E3.2 Recirculation Pump

E3.2.1 Bowl/Casing

E3.2.2 Cover

E3.2.3 Seal Flange

E3.2.4 Closure Bolting

E3.3 Valves (Quality Group A)

E3.3.1 Body

E3.3.2 Bonnet

E3.3.3 Seal Flange

E3.3.4 Closure Bolting

E3.4 Regenerative Heat Exchanger

E3.4.1 Tubing

E3.4.2 Shell

E3.5 Non-Regenerative Heat Exchanger

E3.5.1 Tubing

E3.5.2 Shell

E3.6 Filter/Demineralizer

E3.6.1 Internals

VII AUXILIARY SYSTEMS

E3. REACTOR WATER CLEANUP SYSTEM

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E3.4.1	Regenerative Heat Exchanger	Tubing	SS	Oxygenated water at 288°C. And 10 MPa max.	Crack Initiation and Growth	SCC, IGSCC	NRC GL 88-01 NRC GL 88-01, S1
E3.4.1	Regenerative Heat Exchanger	Tubing	SS	Oxygenated water at 288°C. And 10 MPa max.		MIC	
E3.4.2	Regenerative Heat Exchanger	Shell	HSLAS with SS cladding	Oxygenated water at 288°C. And 10 MPa max.	Crack Initiation and Growth	SCC, IGSCC	NUREG-0313 Rev. 2 NRC GL 88-01 NRC GL 88-01, S1 NRC IN 90-29
E3.4.2	Regenerative Heat Exchanger	Shell	HSLAS with SS cladding	Oxygenated water at 288°C. And 10 MPa max.		MIC	
E3.5.1	Non-Regenerative Heat Exchanger	Tubing	SS	Oxygenated water at 288°C. And 10 MPa max.		MIC	
E3.5.2	Non-Regenerative Heat Exchanger	Shell	HSLAS with SS cladding	Oxygenated water at 288°C. And 10 MPa max.		MIC	

Correction without deletion

add

Addition

add

add

VII AUXILIARY SYSTEMS

E3. REACTOR WATER CLEANUP SYSTEM (Item E3.4.2 continued)

Aging Management Program	Evaluation and Technical Basis	Evaluation
...	... ***(4) Detection of Aging Effects:*** Governed by plant-specific aging management program. {Address MIC and sediment} ...	...

Addition into text

Additions to

VII E3-12

and

VII E3-14

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
Same as the effect of stress relaxation on Item E3.2 Closure Bolting for Recirculation Pump.	*Same as the effect of wear on Item C1.2.4 Closure Bolting for Recirculation Pump.*	No
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a), Subsection NB, or ANSI B31.1, or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Same as the effect of stress corrosion cracking on Item E3.1: Piping and Fittings beyond second Isolation Valve.	*Same as the effect of stress corrosion cracking on Item E3.1: Piping and Fittings beyond second Isolation Valve.*	Yes. Elements 3 through 7 should be further evaluated
Components have been designed or evaluated for fatigue for a 40 y design life, according to the requirements of ASME Section III (edition specified in 10 CFR 50.55a), Subsection NB, or ANSI B31.1, or other evaluations based on cumulative usage factor (CUF).	Fatigue is a time-limited aging analysis (TLAA) to be performed for the period of license renewal, and Generic Safety Issue (GSI)-190 is to be addressed.	Yes TLAA
Materials selection in accordance with guidelines of NUREG-0313, Rev. 2 and requirements of Regulatory Guide 1.43 for the control of stainless steel cladding of low-alloy steels. Inservice inspection governed by plant-specific aging management program.	***(1) Scope of Program:*** The program is focused on managing the effects of SCC of SS cladding on the intended function of the heat exchanger vessel. NUREG-0313 and GL 88-01, respectively, describe the technical basis and staff guidance regarding the problem of IGSCC in BWRs. ***(2) Preventive Actions:*** Mitigation of IGSCC is by selection of material considered resistant to sensitization and IGSCC, e.g., low-carbon grades of austenitic SSs and weld metal, with a maximum carbon of 0.035% and minimum 7.5% ferrite in weld metal. Furthermore, hydrogen water chemistry and stringent control of conductivity is used to inhibit IGSCC. ***(3) Parameters Monitored/ Inspected:*** Governed by plant-specific aging management program. ← INSERT INFORMATION TO ADDRESS M.I.C. AND SEDIMENT ***(4) Detection of Aging Effects:*** Governed by plant-specific aging management program. ***(5) Monitoring and Trending:*** Governed by plant-specific aging management program. ***(6) Acceptance Criteria:*** Governed by plant-specific aging management program. ***(7) Corrective Actions:*** Governed by plant-specific aging management program.. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal.	Yes. Elements 3 through 7 should be further evaluated

VII AUXILIARY SYSTEMS

E3. REACTOR WATER CLEANUP SYSTEM

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
E3.4.2	Regenerative Heat Exchanger	Shell	SS	Oxygenated water at 288°C and 10 MPa max.	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
E3.4.2	Regenerative Heat Exchanger	Shell	HSLAS with SS cladding	Oxygenated water at 288°C. And 10 MPa max.		MIC	
E3.5.1	Non-Regenerative Heat Exchanger	Tubing	SS	Oxygenated water at 288°C and 10 MPa max.	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
E3.5.1	Non-Regenerative Heat Exchanger	Tubing	SS	Oxygenated water at 288°C. And 10 MPa max.		MIC	
E3.5.2	Non-Regenerative Heat Exchanger	Shell	SS	Oxygenated water at 188°C and 1 MPa max.	Cumulative Fatigue Damage	Fatigue	ASME Section III, 1989 Edition. ANSI B31.1. GSI-190.
E3.5.2	Non-Regenerative Heat Exchanger	Shell	HSLAS with SS cladding	Oxygenated water at 288°C. And 10 MPa max.		MIC	

E4. Coolant Storage/Refueling Water Cleanup System

E4.1 Refueling Water Tank (RWT) Heating

E4.1.1 Piping and Fittings

E4.2 RWT Circulation Pump

E4.2.1 Bowl/Casing

E4.2.2 Bolting

E4.3 Valves

E4.3.1 Body

E4.4 Heat Exchanger (RWT Heating)

E4.4.1 Bonnet or Cover

E4.4.2 Tubing

E4.4.3 Shell

E4.5 Refueling Water Tank

E4.5.1 Shell

E4.5.2 Manhole

E4.5.3 Penetrations/Nozzles

E4.5.4 Tank Heating Coil

E4.5.5 Manhole Bolting

E4.5.6 Perimeter Seal

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur. The potential exists for introduction of impurities into the coolant system as contaminants in the boric acid or introduced through the free surface of spent fuel pool (IN 84-18), or from ingress of demineralizer resins (IN 96-11). Corrosion has been observed in safety injection systems, e.g., guide rings of relief valves (IN 98-23) and charging pump casing (IN 94-63).	
Implementation of NRC Generic Letter 88-05 and, based on plant specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWD 2500-1, test and examination category D-B for systems in support of emergency core cooling, containment heat removal, atmosphere cleanup, and reactor residual heat removal.	***(1) Scope of Program:*** The staff guidance of Generic Letter (GL) 88-05 provides assurances that a program has been implemented consisting of measures to ensure that the effects of corrosion caused by leaking coolant containing boric acid does not lead to degradation and provides assurance that the reactor coolant pressure boundary will have a extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. The program includes (a) determination of principal location, (b) examinations requirements and procedures for locating small leaks, and (c) engineering evaluations and corrective actions. ***(2) Preventive Actions:*** Minimizing reactor coolant leakage by frequent monitoring of the locations where potential leakage could occur and repairing the leaky components as soon as possible, prevent or mitigate boric acid corrosion. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of boric acid corrosion on the intended function of the component by detection of coolant leakage by inservice inspection (ISI). Inspection requirements of ASME Section XI specify visual VT-2 (IWA-5240) examination during system leakage test and system hydrostatic test of Class 3 components in support of emergency core cooling, containment heat removal, and reactor residual heat removal, according to Table IWD 2500-1 category D-B. ***(4) Detection of Aging Effects:*** Extent and frequency of inspection appear to be adequate to detect aging effects. ***(5) Monitoring and Trending:*** System leakage test under Section XI is conducted at ≈40-month intervals. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWD-3000 for Class 3 components. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Boric acid wastage observed in nuclear power plants may be classified into two distinct types: (a) corrosion that increases the rate of leakage, e.g., corrosion of closure bolting or fasteners in reactor coolant pressure boundary, and (b) corrosion that occurs some distance from the source of leakage. Some recent incidents of	~~No~~ Yes. Pg VII E4-13 cites "lack of awareness." So - is this conclusion correct? AWS. Further evaluation should include conditions that can lead to boric acid wastage.

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
E4.3.1	Valves (Check Valves, Control Valves, Hand Valves)	Body and Bonnet	SS, CS with SS Cladding	Up to 65°C Chemically Treated Borated Water	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition. NRC IN 84-18. NRC IN 94-63. NRC IN 96-11. NRC IN 98-23. Plant Technical Specifications. EPRI TR 102134.

IF THIS IS TRUE, WHY IS THERE NO NEED FOR FURTHER EVALUATION

DAVS

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) boric acid wastage (IN 86-108 S3) at Calvert Cliffs Unit 1 (Feb. 1994) and Three Mile Island Unit 1 (March 1994) indicate that, although implementation of GL 88-05. ensures timely detection of leakage, there may still be a lack of awareness of the conditions that can lead to boric acid wastage.	
The AMP relies on monitoring and maintaining water chemistry in accordance with the guidelines of EPRI TR 102134 and implemented by the plant technical specifications; inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWB 2500-1, test and examination category D-B for systems in support of emergency core cooling, containment heat removal, atmosphere cleanup, and reactor residual heat removal.	***(1) Scope of Program:*** The program relies on preventive measures to mitigate crevice or pitting corrosion and combination of inservice inspection (ISI) to monitor the effects of corrosion on the intended function of the components. ***(2) Preventive Actions:*** Control of halogens and oxygen in the primary water to less than 5 and 0.01 ppm, respectively, during operation, and monitor and control of water chemistry during shut down. However, preventive actions are considered inadequate because of inadvertent introduction of contaminants into the coolant system either due to unacceptable levels of contaminants in the boric acid, or introduced through the free surface of spent fuel pool which can be a natural collector of airborne contaminants [NRC Information Notice (IN) 84–18]. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of corrosion by ISI to detect coolant leakage. Inspection requirements of ASME Section XI, Table IWD 2500-1, category D-B, specify visual VT-2 (IWA-5240) examination during system leakage and hydrostatic test of all pressure retaining Class 3 components. ***(4) Detection of Aging Effects:*** Degradation of the component due to crevice and pitting corrosion cannot occur without leakage of coolant. However, extent and frequency of inspection may be inadequate; inspection of representative components and susceptible locations should be undertaken to provide additional assurance that significant degradation is not occurring. Based on piping/ component geometry and fluid flow conditions, susceptible locations can be identified and evaluated. ***(5) Monitoring and Trending:*** System leakage test under Section XI is conducted at ≈40-month intervals. However, this may not be sufficiently frequent to detect the effects of this ARD, and a supplemental inspection program may be needed. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWD-3000 for Class 3 components. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWA-5250. Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur. The potential exists for introduction of impurities into the coolant	Yes Elements 4 and 5 should be further evaluated

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E4.4.1 thru E4.4.3	Heat Exchanger (if used) (RWT Heating)	Bonnet or Cover, Tubing, Shell	Bonnet/ Cover & Tubing: SS, Shell: CS	Chemically Treated Borated Water; and Chemically Treated Heating Water	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition. NRC IN 84-18.
E4.4.3, E4.4.4	Heat Exchanger (if used) (RWT Heating)	Shell (External Surface), Bolting	Shell: CS, Nuts: CS, Bolts/Studs: Alloy Steel	Air, Leaking Chemically Treated Borated Water	Loss of Material	Corrosion/ Boric Acid Wastage of External Surfaces	NRC GL 88-05. ASME Section XI, 1989 Edition. NRC IN 86-108 S3.

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
The applicable AMP relies on material selection guidelines of Regulatory Guide (RG) 1.44 to avoid sensitization of stainless steels, monitoring and maintaining water chemistry in accordance with the guidelines of EPRI TR 102134 and implemented by the plant technical specifications, and inservice inspection is in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWD 2500-1, test and examination category C-H for pressure retaining Class 2 components.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on the intended function of the component. ***(2) Preventive Actions:*** Selection of material in compliance with the requirements of Regulatory Guide (RG) 1.44 prevents or mitigates SCC. Control of halogens and oxygen in the primary water to less than 5 and 0.01 ppm, respectively, during operation, and monitor and control of water chemistry during shut down, mitigate potential of SCC. However, preventive actions are considered inadequate because of inadvertent introduction of contaminants into the coolant system either due to unacceptable levels of contaminants in the boric acid, or introduced through the free surface of spent fuel pool which can be a natural collector of airborne contaminants [NRC Information Notice (IN) 84-18]. ***(3) Parameters Monitored/ Inspected:*** The AMP monitors the effects of SCC on intended function of the component by detecting leakage by ISI. Inspection requirements of ASME Section XI Table IWD 2500-1 category C-H specify visual VT-2 (IWA-5240) examination during system leakage test and system hydrostatic test of all pressure retaining Class 2 components. ***(4) Detection of Aging Effects:*** Degradation of the component due to SCC cannot occur without leakage of coolant. However, extent and frequency of inspection may be inadequate; inspection of representative components and susceptible locations should be undertaken to provide additional assurance that significant SCC is not occurring. Based on piping/component geometry and fluid flow conditions, susceptible locations can be identified and evaluated. ***(5) Monitoring and Trending:*** System leakage test under Section XI is conducted at ≈40-month intervals. However, this may not be sufficiently frequent to detect the effects of this ARD, and a supplemental inspection program may be needed. ***(6) Acceptance Criteria:*** Any relevant conditions that may be detected during the leakage and hydrostatic tests are evaluated in accordance with IWC-3516. ***(7) Corrective Actions:*** Repair and replacement are in conformance with IWA-4000 and IWB-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Although the primary pressure boundary piping of PWRs have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, significant potential of SCC exists from inadvertent introduction of contaminants into the primary coolant system (IN 84-18). SCC has been observed in safety injection lines (IN 97-19 and 84-18), charging pump casing cladding (INs 80-38 and 94-63), internal bolting in swing check valves (IN 89-02), and instrument nozzles in safety injection tanks (IN 91-05).	Yes Elements 4 and 5 should be further evaluated

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E4.5.4	Refueling Water Tank (RWT)	Heating Coil	SS	Chemically Treated Borated Water; and Chemically Treated Heating Water	Loss of Material	Crevice and Pitting Corrosion	ASME Section XI, 1989 Edition.
E4.5.5	Refueling Water Tank (RWT)	Manhole Bolting	Nuts: CS, Bolts/Studs: Alloy Steel	Air, Leaking Chemically Treated Borated Water	Loss of Material	Corrosion/ Boric Acid Wastage of External Surfaces	NRC GL 88-05. ASME Section XI, 1989 Edition. NRC IN 86-108 S3.
E4.5.6	Refueling Water Tank (RWT)	Perimeter Seal	Cold Plastic Coal Tar Pitch Flashing	Air	Loss of elasticity (drying out)	Weathering	-

no water?? moisture?

??

what has been weathering effect observed at plants?

or do we really care?

If important (i.e. cracking can allow moisture penetration to underside of RWT which in turn sets up chemical impurities leading to IGSC, doesn't this static component deserve more attention?

AWS.

E5. Shutdown Cooling System (Older BWR)

E5.1 Piping

E5.1.1 Piping and Fittings

E5.1.2 Bolting

E5.2 Pump

E5.2.1 Bowl/Casing

E5.2.2 Bolting

E5.3 Valves

E5.3.1 Body and Bonnet

E5.3.2 Bolting

E5.4 Heat Exchanger

E5.4.1 Tubes

E5.4.2 Tubesheet

E5.4.3 Channel and Head

E5.4.4 Shell

E5.4.5 Bolting

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) evaluated in accordance with IWC-3100 and acceptance standards of IWC-3400 and IWC-3516 for Class 2 components. ***(7) Corrective Actions:*** Prior to service, corrective measures are needed to meet the requirements of IWB-3142 and IWA-5250. Repair and replacement are in conformance with IWA-4000. ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur. [redacted]	Delete?
Guidelines of NUREG-0313, Rev. 2 and NRC Generic letter (GL) 88-01 and its Supplement 1; and based on plant technical specifications, inservice inspection in conformance with ASME Section XI (edition specified in 10 CFR 50.55a), Table IWC 2500-1, examination category C-G for pressure retaining welds in Class 2 valves and testing category C-H for system leakage. Water chemistry is monitored and maintained in accordance with EPRI guidelines in BWRVIP-29 and TR-103515 to minimize the potential of crack initiation and growth.	***(1) Scope of Program:*** The program includes preventive measures to mitigate stress corrosion cracking (SCC) of stainless steel (SS) and inservice inspection (ISI) to monitor the effects of SCC on intended function of the valves. NUREG-0313 and GL 88-01, respectively, describe the technical basis and staff guidance regarding the problem of IGSCC in BWRs. ***(2) Preventive Actions:*** Mitigation of IGSCC is by selection of material considered resistant to sensitization and IGSCC, e.g., low-carbon grades of cast SSs and weld metal, with a maximum carbon of 0.035% and minimum 7.5% ferrite. Water chemistry is monitored and maintained in accordance with EPRI guidelines in BWRVIP-29 and TR-103515 to minimize the potential of crack initiation and growth. Also, hydrogen water chemistry and stringent control of conductivity is used to inhibit IGSCC. ***(3) Parameters Monitored/Inspected:*** The AMP monitors the effects of SCC on intended function of the valves by detection and sizing of cracks by ISI. Inspection requirements of Table IWC 2500-1 for Class 2 valves, category C-G specifies for all valves in each piping run examined under category C-F-1, surface examination of either the inside or outside surface of all welds extending 1/2 in. on either side of the weld. In a group of multiple valves of similar design, size, function, and service in a system, examination of only one valve is required. ***(4) Detection of Aging Effects:*** Degradation of valves due to SCC can not occur without crack initiation or degradation of pump performance; ISI schedule assures detection of cracks or degradation of valve performance before the loss of intended function of the valves. ***(5) Monitoring and Trending:*** Inspection schedule in accordance with IWC-2400 should provide timely detection of cracks. All welds are inspected each inspection period from at least one valve in each group with similar design and performing similar functions in the system. Visual examination is required only when the valve is disassembled for maintenance, repair, or volumetric examination, but at least once during the	No

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References

INSERT

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
E5.4.1 Thru E5.4.4	Heat Exchanger	Tubes, Tubesheet, Channel & Head, Shell	Tubes: SS Tubesheet: CS (SS Cladding on Channel Side); Channel & Head: CS; Shell: CS	Oxygenated Water; and Treated Component Cooling Water		MIC	

VII AUXILIARY SYSTEMS

E5. SHUTDOWN COOLING SYSTEM (Old Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environment	Aging Effect	Aging Mechanism	References
E5.3.1	Valves ...	Body and Bonnet	SS Forging ...	Oxygenated Water ...	Loss of Material	Crevice Pitting ...	ASME Section XI ...
E5.4.1 Thru E5.4.4	Heat Exchanger	Tubes, Tubesheet, Channel & Head, Shell	Tubes: SS Tubesheet: CS (SS Cladding on Channel Side); Channel & Head: CS; Shell: CS	Oxygenated Water; and Treated Component Cooling Water	Loss Of Material	Crevice Pitting Corrosion MIC	ASME Section XI, 1989 Edition Plant Technical Specifications
E5.4.1 Thru E5.4.4	Heat Exchanger	Tubes, Tubesheet, Channel & Head, Shell	Tubes: SS Tubesheet: CS (SS Cladding on Channel Side); Channel & Head: CS; Shell: CS	Oxygenated Water; and Treated Component Cooling Water			

VII AUXILIARY SYSTEMS

E5. SHUTDOWN COOLING SYSTEM (Old Boiling Water Reactor) (Item E5.3.1 Continued)

Existing Aging Management Program	Evaluation and Technical Basis	Further Evaluation
...	...***(10) Operating Experience:*** Localized corrosion is likely to occur at crevice geometry where buildup of impurities can occur. ~~Failure of steam turbine governor valves due to corrosion scale buildup has occurred in RCIC and AFW systems (NRC IN 96-24)~~	...
(Item E5.4.1 Thru E5.4.4 Continued)		
...	...***(2) Preventive Actions:*** ... The parameters monitored include halogens, sulfates, oxygen, and pH in the primary water, and in addition to these, dissolved copper and iron, ~~and~~ suspended solids, microbiological organisms, and sediment in the component cooling water. ...	No

F1. Control Room Area Ventilation System

F1.1 Duct

F1.1.1 Duct, Fittings, and Access Doors

F1.1.2 Equipment Frames and Housing

F1.1.3 Flexible Collars between Ducts and Fans

F1.1.4 Seals in Dampers and Doors

F1.2 Air Handler Heating/Cooling

F1.2.1 Heating/Cooling Coils

F1.3 Piping

F1.3.1 Piping and Fittings

F1. Control Room Area Ventilation System

F1.1 Duct

- F1.1.1 Duct, Fittings, and Access Doors
- F1.1.2 Equipment Frames and Housing
- F1.1.3 Flexible Collars between Ducts and Fans
- F1.1.4 Seals in Dampers and Doors

F1.2 Air Handler Heating/Cooling

- F1.2.1 Heating/Cooling Coils

F1.3 Piping

- F1.3.1 Piping and Fittings

F1.4 Pumps (Casing)
F1.5 Valves (Bodies)
F1.6 Tanks

COMMENTS:

1. Consider adding these passive components in the safety-related Chilled Water System (CWS) which often is a subsystem of System F1 (Control Room Area Ventilation System). At some plants, CWS is a seperate system. Note that CWS is not included anywhere else in the GALL report. If not included here, address CWS separately elsewhere in the GALL report. Other passive component of CWS is piping, which is already here (F1.3).
2. Modify the F1 table to address all atributes (the 9 items in top row) for each of added components (F1.4, 5, and 6).
3. Consider comments 1. and 2. above for the other Three ventilation systems in the GALL report. (Section VII F2, F3, and F4), some plants have CWS as subsystem for these three systems or as a separate CWS, supporting the ventilation systems (see Comment 1).

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F2. Auxiliary and Radwaste Area Ventilation System

F2.1 Duct

F2.1.1 Duct, Fittings, and Access Doors

F2.1.2 Equipment Frames and Housing

F2.1.3 Flexible Collars between Ducts and Fans

F2.1.4 Seals in Dampers and Doors

F2.2 Air Handler Heating/Cooling

F2.2.1 Heating/Cooling Coils

F2.3 Piping

F2.3.1 Piping and Fittings

F3. Engineered Safety Feature Ventilation System (Primary Containment Area)

F3.1 Duct

F3.1.1 Duct, Fittings, and Access Doors

F3.1.2 Equipment Frames and Housing

F3.1.3 Flexible Collars between Ducts and Fans

F3.1.4 Seals in Dampers and Doors

F3.2 Air Handler Heating/Cooling

F3.2.1 Heating/Cooling Coils

F3.3 Piping

F3.3.1 Piping and Fittings

F4. Diesel Generator Building Ventilation System

F4.1 Duct

F4.1.1 Duct, Fittings, and Access Doors

F4.1.2 Equipment Frames and Housing

F4.1.3 Flexible Collars between Ducts and Fans

F4.1.4 Seals in Dampers and Doors

F4.2 Air Handler Heating/Cooling

F4.2.1 Heating/Cooling Coils

F4.3 Piping

F4.3.1 Piping and Fittings

G. Fire Protection

G.1 Intake Structure

G.1.1 Fire Barrier Penetration Seals

G.1.2 Fire Barrier Walls, Ceiling, and Floors

G.1.3 Fire Rated Doors

G.2 Turbine Building

G.2.1 Fire Barrier Penetration Seals

G.2.2 Fire Barrier Walls, Ceiling, and Floors

G.2.3 Fire Rated Doors

G.3 Auxiliary Building

G.3.1 Fire Barrier Penetration Seals

G.3.2 Fire Barrier Walls, Ceiling, and Floors

G.3.3 Fire Rated Doors

G.4 Diesel Generator Building

G.4.1 Fire Barrier Penetration Seals

G.4.2 Fire Barrier Walls, Ceiling, and Floors

G.4.3 Fire Rated Doors

G.5 Primary Containment

G.5.1 Fire Barrier Walls, Ceiling, and Floors

G.5.2 Fire Rated Doors

G.6 High-Pressure Service Water System

G.6.1 Piping and Fittings

G.6.2 Filter, Fire Hydrants, Mulsifier, Pump Casing, Sprinkler, Strainer, and Valve Bodies

G.7 Reactor Coolant Pump Oil Collect System

G.7.1 Tank

G.7.2 Piping, Tubing, Valve Bodies

G.8 Diesel Fire System

G.8.1 Diesel-Driven Fire Pump and Fuel Supply Line

G. Fire Protection

System, Structures, and Components

The system, structure, and components included in this table comprise the fire protection system for both boiling water reactors (BWRs) and pressurized water reactors (PWRs) and
* consist of several Class 1 structures and mechanical systems. The Class 1 structures include intake structure, turbine building, auxiliary building, diesel generator building, and primary containment, and structural components include fire barrier wall, ceiling, floor, fire door, and penetration seal. Mechanical systems include high pressure service water system, reactor coolant pump oil collect system, and diesel fire system, and mechanical components include piping and fittings, filter, fire hydrant, mulsifyer, pump, valves, sprinkler, and strainer. All the mechanical components are classified as Group C Quality Standards.

Pumps and valves are considered to be active components and pump internals and seats, discs, bolting, and other valve items should be covered by the plant maintenance program.

System Interfaces

The systems that interface with the fire protection system include various Class 1 structures and component supports (Chapter III), closed cycle cooling water system (Table VII C2) and the Diesel Fuel Oil System (Table VII H1).

* what about electrical systems/components associated with fire protection? Even if they are addressed in chapter VI on Electrical Components, they should be recognized and cross-referenced.

J. VORA.

H1. Diesel Fuel Oil System

H1.1 Piping

H1.1.1 Aboveground Pipe and Fittings

H1.1.2 Underground Pipe and Fittings

H1.2 Valves

H1.2.1 Body and Bonnet

H1.2.2 Closure Bolting

H1.3 Pump

H1.3.1 Casing

H1.3.2 Closure Bolting

H1.4 Tank

H1.4.1 Tank Internal Surfaces

H1.4.2 Tank External Surfaces

H1.4.3 Caulking and Sealant

H1. Diesel Fuel Oil System

System, Structures, and Components

The system, structures, and components included in this table comprise the diesel fuel oil system and consist of above ground and underground piping, valves, pump, and tank. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the diesel fuel oil system are classified as Group C Quality Standards.

System Interfaces

The system that interfaces with the diesel fuel oil system is the emergency diesel generator system (Table VII H2).

General comments for consideration, as appropriate.

For large underground fuel oil tanks whose capacity is such that with normal usage fuel can remain for more than 2 years and where there is no system to assure homogeneity of the stored fuel, there shall be an aging management program to verify (1) the deterioration of aged fuel oil and (2) the periodicity of required filter changes based on the available reserve engine filter capacity with the actual aged fuel, in order to assure the ability of plants to perform a design basis run of their emergency diesels without fuel starvation.

H2. Emergency Diesel Generator System

H2.1 Diesel Engine Cooling Water Subsystem

H2.1.1 Pipe and Fittings

H2.2 Diesel Generator Air Starting Subsystem

H2.2.1 Pipe and Fittings

H2.2.2 Hand Valve

H2.2.3 Check Valve

H2.2.4 Drain Trap

H2.2.5 Air Accumulator Vessel

H2.3 Diesel Generator Combustion Air Intake Subsystem

H2.3.1 Piping and Fittings

H2.3.2 Filter

H2.3.3 Muffler

H2.4 Diesel Generator Combustion Exhaust Air Subsystem

H2.4.1 Piping and Fittings

H2.4.2 Muffler

H2.5 Diesel Generator Fuel Oil Subsystem

H2.5.1 Day Tank

H2.5.2 Dip Tank

H2.5.3 Strainer

H2. Emergency Diesel Generator System

System, Structures, and Components

The system, structures, and components included in this table comprise the emergency diesel generator system and contain piping, valves, filter, muffler, strainer, day tank, and dip tank for cooling water, starting air, combustion air intake, combustion exhaust air, and diesel fuel oil subsystems. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the emergency diesel generator system are classified as Group C Quality Standards.

System Interfaces

The systems that interface with the emergency diesel generator system include the diesel fuel oil system (Table VII H1) and the closed cycle cooling water system (Table VII C2).

1. In some plants, the open cycle cooling system also interfaces with EDG system, such as Haddam Neck plant in which the EDG cooling water heat exchanger uses SW for cooling

2. Diesel engine Jacket Water heat exchanger should be also included in the aging management review.

3. Vibration was identified as a significant aging degradation factor (NUREG/CR-5057), such as fatigue failures of small bore piping due to engine-induced vibration. Crackings of small bore pipings have resulted in inoperability of EDGs. The cracked lines have found in EDG lube oil, fuel oil, and cooling water systems. Many of these cracks were not detected by ISI, but only discovered after the cracks propagated completely through the tube wall and fluid was observed leaking from the pipes.

I Liquid Waste Disposal System

I.1 Piping

I.2 Pumps

I.3 Valves

I.4 Tanks

I.5 Evaporators

I.6 Demineralizers

I.7 Gas Strippers

I Liquid Waste Disposal System

I.1 Piping

I.2 Pumps

I.3 Valves

I.4 Tanks

I.5 Evaporators

I.6 Demineralizers

I.7 Gas Strippers

I.8 Filters (Casing)

COMMENT:

1. Consider adding Filters (Item I.8 above). Similar to tanks, evaporators, and demineralizers (Items I.4, I.5, and I.6 above), filters are also common passive components of this system.

2. Modify the table in Section I to address all attributes (the 9 items in top row) for the added component (I.8).

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CHAPTER VIII

(10/15/99)

STEAM AND POWER CONVERSION SYSTEM

Major Plant Sections

A. Steam Turbine System

B1. Main Steam System (PWR)

B2. Main Steam System (BWR)

C. Extraction Steam System

D1. Feedwater Systems (PWR)

D2. Feedwater Systems (BWR)

E. Condensate System

F. Steam Generator Blowdown System (PWR)

G. Auxiliary Feedwater (AFW) System (PWR)

A. Steam Turbine System

A.1 Piping and Fittings

A.1.1 HP Turbine to MSR

A.1.2 MSR to LP Turbine

A. **Steam Turbine System**

A.1 Piping and Fittings

A.1.1 HP Turbine to MSR
A.1.2 MSR to LP Turbine

add →

A.2 Valves

A.3 Moisture Separator/Reheater

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References

INSERT

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
A.2.1	Valves (Stop, Control or Governor, Intermediate Stop and Control or Combined Intermediate, Bypass or Steam Dumps, Atmospheric Dumps, Main Steam Safety, or Safety/Relief)	Body			Wall Thinning	Erosion/Corrosion	
A.3.1	Moisture Separator Moisture Separator/ Reheater	Tubes, Tubesheet Channel Head Shell			Wall Thinning	Erosion/Corrosion	
A.3.1	Moisture Separator Moisture Separator/ Reheater	Tubes, Tubesheet Channel Head Shell				MIC	

B1. Main Steam System (PWR)

B1.1 Piping and Fittings

B1.1.1 Steam Lines to Main Turbine

B1.1.2 Lines to FW and AFW Pump Turbines

B1.1.3 Lines to Moisture Separator/Reheater

B1.1.4 Turbine Bypass

B1.1.5 Steam Drains

B1.2 Valves (Check, Control, Hand, Motor Operated Valves)

B1.2.1 Body

B1. Main Steam System (PWR)

B1.1 Piping and Fittings

B1.1.1 Steam Lines to Main Turbine

B1.1.2 Lines to FW and AFW Pump Turbines

B1.1.3 Lines to Moisture Separator/Reheater — This is redundant with [illegible]

B1.1.4 Turbine Bypass

B1.1.5 Steam Drains

B1.2 Valves (Check, Control, Hand, Motor Operated Valves)

B1.2.1 Body

B1.3 Main Condenser

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B1.2.1	Valves (Check Valves, Control Valves, Hand Valves, Motor Operated Valves)	Body	CS	320°C Steam	Wall Thinning	E/C	NUREG-1344. NRC GL 89-08. NRC IN 89-53. NRC IN 91-18. NRC IN 91-18 S1. NRC IN 93-21. NRC IN 97-84. EPRI NSAC-202L-R2. EPRI TR-102134 Rev. 3.

INSERT

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B1.3.1	Main Condenser	Tubes, Tubesheet, Channel Head, Shell			Wall Thinning	Erosion/ Corrosion	
B1.3.1	Main Condenser	Tubes, Tubesheet, Channel Head, Shell				MIC	

B2. Main Steam System (BWR)

B2.1 Piping and Fittings

B2.1.1 Steam Lines to Main Turbine (Group B)

B2.1.2 Steam Lines to Main Turbine (Group D)

B2.1.3 Lines to FW Pump Turbines

B2.1.4 Lines to Moisture Separator/Reheater

B2.1.5 Turbine Bypass

B2.1.6 Steam Drains

B2.2 Valves (Check, Control, Hand, Motor-Operated Valves)

B2.2.1 Body

B2.2.2 Bolting

B2. Main Steam System (BWR)

B2.1 Piping and Fittings

B2.1.1 Steam Lines to Main Turbine (Group B)

B2.1.2 Steam Lines to Main Turbine (Group D)

B2.1.3 Lines to FW Pump Turbines

B2.1.4 Lines to Moisture Separator/Reheater (This is redundant w/ VIII.A.1.1)

B2.1.5 Turbine Bypass

B2.1.6 Steam Drains

INSERT

B2.1.7 Steam Line to HPCI turbine operated Valves)

B2.1.8 Steam Line to RCIC turbine

B2.2.2 Bolting

INSERT

B2.3 Main Condenser

VIII STEAM AND POWER CONVERSION SYSTEMS

B2. MAIN STEAM SYSTEM (Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B2.1.7	Steam Line to HPCI Turbine	Piping and Fittings					
B2.1.8	Steam Line to RCIC Turbine	Piping and Fittings					
B2.2	Condenser	Tubes, Tubesheet, Channel Head, Shell			Wall Thinning	Erosion/ Corrosion	
B2.2	Condenser	Tubes, Tubesheet, Channel Head, Shell				MIC	

insert

VIII STEAM AND POWER CONVERSION SYSTEMS
B2. MAIN STEAM SYSTEM (Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B2.1.7	Steam Line to HPCI Turbine	Piping and Fittings					
B2.1.8	Steam Line to RCIC Turbine	Piping and Fittings					

INSERT

VIII STEAM AND POWER CONVERSION SYSTEMS

B2. MAIN STEAM SYSTEM (Boiling Water Reactor)

Item	Structure and Component	Region of Interest	Material	Environ-ment	Aging Effect	Aging Mechanism	References
B2.3	Condenser	Tubes, Tubesheet, Channel Head, Shell			Wall Thinning	Erosion/ Corrosion	
B2.3	Condenser	Tubes, Tubesheet, Channel Head, Shell				MIC	

C. Extraction Steam System

C.1 Piping and Fittings

C.1.1 Lines to Feedwater Heaters

C.1.2 Steam Drains

C.2 Valves

C.2.1 Body

D1. Feedwater Systems (PWR)

D1.1 Main Feedwater Line

D1.1.1 Pipe and Fittings

D1.2 Valves (Control, Check, and Hand Valves)

D1.2.1 Body

D1.3 Feedwater Pump (Steam Turbine- and Motor-Driven)

D1.3.1 Casing

D1.3.2 Suction and Discharge Lines

D1. Feedwater Systems (PWR)

D1.1 Main Feedwater Line

D1.1.1 Pipe and Fittings

D1.2 Valves (Control, Check, and Hand Valves)

D1.2.1 Body

D1.3 Feedwater Pump (Steam Turbine- and Motor-Driven)

D1.3.1 Casing

D1.3.2 Suction and Discharge Lines

Add: 1. Feedwater Heaters

2. Feedwater Pump Lube oil Cooler

VIII STEAM AND POWER CONVERSION SYSTEM

D1. Feedwater System (Pressurized Water Reactor)

should include "feedwater heaters"

System, Structures, and Components

The system, structures, and components included in this table comprise the main feedwater system for pressurized water reactors (PWRs) extending from the condensate system to the outermost feedwater isolation valve on the feedwater lines to the steam generator, and consist of the main feedwater lines, feedwater pumps, and valves. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components in the feedwater system are classified as Group D Quality Standards. Portion of the feedwater system extending from the secondary side of the steam generator up to the second isolation valve outside the containment is classified as Group B or C standards and is covered in Tables IV D1 and D2. The aging management program for isolation valves in the feedwater system is reviewed in Table V C.

The pumps and valves internals are considered to be active components. They perform their intended functions with moving parts or with a change in configuration and are not subject to aging management review pursuant to 10 CFR 54.21(a)(1)(i). and (ii)

System Interfaces

The systems that interface with the feedwater system include the steam generator (Table IV D1 and D2), main steam system (Table VIII B1), extraction steam system (Table VIII C), condensate system (Table VIII E), and auxiliary feedwater system (Table VIII G).

D2. Feedwater Systems (BWR)

D2.1 Main Feedwater Line

D2.1.1 Pipe and Fittings

D2.1.2 Bolting for Flange Connections

D2.2 Valves (Control, Check, and Hand Valves)

D2.2.1 Body

D2.3 Feedwater Pump (Steam Turbine- and Motor-Driven)

D2.3.1 Casing

D2.3.2 Suction and Discharge Lines

D2. Feedwater Systems (BWR)

D2.1 Main Feedwater Line

D2.1.1 Pipe and Fittings

D2.1.2 Bolting for Flange Connections

D2.2 Valves (Control, Check, and Hand Valves)

D2.2.1 Body

D2.3 Feedwater Pump (Steam Turbine- and Motor-Driven)

D2.3.1 Casing

D2.3.2 Suction and Discharge Lines

Add: 1. Feedwater heaters

2. Feedwater pump lube oil cooler

VIII STEAM AND POWER CONVERSION SYSTEM
D2. Feedwater System (Boiling Water Reactor)

should include "Feedwater heaters"

System, Structures, and Components

The system, structures, and components included in this table comprise the main feedwater system for boiling water reactors (BWRs) extending from the condensate and condensate booster system to the outermost feedwater isolation valve on the feedwater lines to the reactor vessel, and consist of the main feedwater lines, feedwater pumps, and valves. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," portions of the feedwater system extending from the outermost containment isolation valves up to and including the shutoff valve or the first valve that is either normally closed or capable of closure during all modes of normal reactor operation are classified as Group B quality standards, and the remainder as Group D. Portion of the feedwater system extending from the reactor vessel up to the second isolation valve outside the containment is classified as Group A standards and is covered in Table IV C1. The aging management program for isolation valves in the feedwater system is reviewed in Table V C.

The pumps and valves internals are considered to be active components. They perform their intended functions with moving parts or with a change in configuration and are not subject to aging management review pursuant to 10 CFR 54.21(a)(1)(i). and (ii)

System Interfaces

The systems that interface with the feedwater system include the reactor coolant pressure boundary (Table IV C1), main steam system (Table VIII B2), extraction steam system (Table VIII C), and condensate system (Table VIII E).

E. Condensate System

E.1 Condensate Lines

E.1.1 Piping and Fittings

E.2 Valves

E.2.1 Body

E.3 Condensate Pumps (Main and Booster Pumps)

E.3.1 Casing

E.4 Condensate Coolers/Condensers

E.4.1 Tubes

E.4.2 Tubesheet

E.4.3 Channel Head

E.4.4 Shell

E.5 Condensate Storage

E.5.1 Tank

E.6 Condensate Cleanup System

E.6.1 Piping and Fittings

E.6.2 Demineralizer

E.6.3 Strainer

E.6.4 Filter

F. Steam Generator Blowdown System (PWR)

F.1 Blowdown Lines

F.1.1 Pipe and Fittings (Group B)

F.1.2 Pipe and Fittings (Group D)

F.2 Valves

F.2.1 Body

F.3 Blowdown Pump

F.3.1 Casing

F.4 Blowdown Heat Exchanger

F.4.1 Tubes

F.4.2 Tubesheet

F.4.3 Channel Head

F.4.4 Shell

G. Auxiliary Feedwater (AFW) System (PWR)

G.1 Auxiliary Feedwater Piping

G.1.1 Pipe and Fittings (Above Ground)

G.1.2 Pipe and Fittings (Buried)

G.2 AFW Pumps (Steam Turbine- and Motor-Driven)

G.2.1 Casing

G.2.2 Suction and Discharge Lines

G.2.3 Bolting

G.3 Valves (Control, Check, Hand Valves)

G.3.1 Body

G.4 Condensate Storage (Emergency)

G.4.1 Tank

G.5 Bearing Oil Coolers

G.5.1 Shell

G.5.2 Tubes

G.5.3 Tubesheet

System, Structures, and Components

The system, structures, and components included in this table comprise the auxiliary feedwater (AFW) system for pressurized water reactors (PWRs) extending from the condensate storage system to the outermost containment isolation valve on the auxiliary feedwater lines to the steam generator, and consist of auxiliary feedwater piping, auxiliary feedwater pumps, valves, and pump turbine oil coolers. Based on US Nuclear Regulatory Commission Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," portions of the auxiliary feedwater system that are required for their safety functions and that either do not operate during any mode of normal reactor operation or cannot be tested adequately, should be classified as Group B quality standards, and the remainder classified as Group C. Portion of the auxiliary feedwater system extending from the secondary side of the steam generator up to the second isolation valve outside the containment is classified as Group B standard, and is covered in Tables IV D1 and D2. The aging management program for isolation valves in the auxiliary feedwater system is reviewed in Table V C.

Auxiliary feedwater lines also connect to main feedwater line.

The pumps and valves internals are considered to be active components. They perform their intended functions with moving parts or with a change in configuration and are not subject to aging management review pursuant to 10 CFR 54.21(a)(1)(i). (ii)

System Interfaces

The systems that interface with the auxiliary feedwater system include the steam generator (Tables IV D1 and D2), main steam system (Table VIII B1), and condensate system (Table VIII E).

1. Cavitation contributed to service wear of the AFW pump casing and should be considered as an aging mechanism for the pump casing:

(a). Operation of pumps at low-flow conditions for extended periods of time can cause cavitation damage (inlet flow recirculation) independent of available NPSH. — NUREG/CR4597 "Aging and Service Wear of AFW Pumps for PWRs"

(b) Monitoring for steam binding of AFW pump:
Back leakage of main feedwater past the isolation check valves in the AFW system can cause steam binding of AFW pumps and lead to pump cavitation when the pumps are subsequently started up. NRC Bulletin 85-01 requires monitoring the AFW pump discharge line for indication of the presence of steam and hot water.

except for PWRs with present ... where a ... portion of the main feedwater is diverted through AFW lines during normal operation. This portion of AFW lines have experienced significant wall thinning. (exposed to hot MFW flowing at high velocity)

VIII STEAM AND POWER CONVERSION SYSTEMS

G. Auxiliary Feedwater (AFW) SYSTEM (Pressurized Water Reactor)

Existing Aging Management Program (AMP)	Evaluation and Technical Basis	Further Evaluation
	(continued from previous page) ***(8 & 9) Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. ***(10) Operating Experience:*** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC Bulletin No. 87-01, INs 86-106 & supplements, 91-19, 91-28, 92-35, 95-11). For most AFW system, fluid flow, temperature, and pressure drop conditions are unlikely to cause cavitation erosion; it is limited to locations downstream of flow orifices. The AMP outlined in NUREG-1344 and implemented through GL 89-08 has provided effective means of ensuring the structural integrity of all high-energy carbon steel systems.	
The program relies on preventive measures to mitigate corrosion by monitoring and control of water chemistry in accordance with the EPRI guidelines of TR-102134, Rev. 3.	***(1) Scope of Program:*** The program relies on monitoring and control of water chemistry (EPRI TR 102134 Rev. 3) for managing the effects of loss of material due to general, crevice, or pitting corrosion. ***(2) Preventive Actions:*** Stringent control of system water chemistry by frequent monitoring and timely corrective action when specified impurity levels are exceeded prevent or mitigate corrosion. The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of secondary and demineralized water chemistry. ***(3) Parameters Monitored/Inspected:*** The parameters monitored are the water pH and concentration of corrosive impurities (chlorides, sulfates, dissolved oxygen, sodium, silica). ***(4) Detection of Aging Effects:*** An one-time inspection of representative sample of the system population and most susceptible locations in the system should be conducted to verify effectiveness of the chemistry control program and to ensure that significant degradation is not occurring or that it would not affect the CLB and the component intended function will be maintained during the extended period. Follow up actions are based on the inspection results and plant technical specification. Inspection is performed in accordance with the requirements of ASME Code, 10CFR50 Appendix B, and ASTM standards, using a variety of nondestructive techniques including visual, ultrasonic, and surface techniques. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. Requirements for training and qualification of personnel and performance demonstration for procedures and equipment is in conformance with Appendices VII and VIII of ASME Section XI, or any other formal program approved by the NRC. ***(5) Monitoring and Trending:*** The frequency of sampling water chemistry varies from continuous, daily, weekly, or as required based on plant operating conditions. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions. ***(6) Acceptance Criteria:*** Maximum levels	Yes, Element 4 should be further evaluated

CHAPTER IX

SUMMARY AND CONCLUSIONS

(To be developed)

APPENDIX

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

The license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an aging management review will be adequately managed to assure that their intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. ~~The applicant's aging management programs for license renewal should contain the elements of corrective actions, confirmation process, and administrative controls.~~ The licensee's existing ~~program to address these elements are the~~ quality assurance (QA) program as required by 10 CFR Part 50, Appendix B must be continued in its entirety during the preparations for extended operating life, and for the operations themselves. In addition, the licensee's QA program should have demonstrated continued effectiveness as measured by generally accepted performance measures.

Finally, the licensee must address how the unique requirements of evaluating and testing of the plant passive systems and components will be addressed. Particular attention must be paid to the qualifications of individuals performing and reviewing work that has not been part of plant operations during the normal lifetime of the plant.

~~Corrective action is an element addressed by the applicant's QA program. Criteria 16 of 10 CFR Part 50, Appendix B, requires measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Should the nonconformance be considered significant, measures must be implemented that assure the cause of the nonconformance be determined and corrective action is taken to preclude repetition of the nonconformance. In addition, the cause of the condition and the corrective action implemented must be documented and reported to the appropriate level of management.~~
~~The applicant's QA program contains effective corrective actions when the specified acceptance criteria has not been met. The applicant's QA program ensures that corrective actions, including root cause determination and prevention of recurrence, will be timely. The corrective action must recommend or provide solutions to the nonconformance. If corrective actions permit analysis without repair or replacement, the basis of the analysis ensures that the intended function(s) for the structure and components will be maintained consistent with the CLB.~~
~~Confirmation process is an element addressed by the applicant's QA program. Criteria 16 of 10 CFR Part 50, Appendix B, requires measures to be taken that preclude repetition of a nonconformance. In addition, follow-up action must be taken to verify implementation of the proposed corrective action. Verification of corrective action implementation is an essential step in the confirmation process. The confirmation process ensures that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.~~
~~For prevention and mitigation programs, the effectiveness of these programs should be periodically verified. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition monitoring program (ultrasonic inspection) to verify~~

that corrosion is indeed insignificant. When corrective actions are necessary, there should be followup activities to confirm that the corrective actions are completed, root cause determination is performed, and recurrence is prevented.

Administrative controls are also addressed by the applicant's QA program. Administrative controls are the provisions relating to organization and management, policies, orders, instructions, procedures, record keeping, and designations of authority and responsibility, which are necessary to assure operation of the facility in a safe manner. The requirement to include administrative controls in the applicant's QA program is specified in 10 CFR §50.34(b)(6)(ii) and §50.36(c)(5) and Appendix B of 10 CFR Part 50. In addition, Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)," provides guidance in the application of administrative controls. Regulatory Guide 1.33 describes proper application of administrative controls and provides examples of typical administrative control procedures. For example, the requirement to prepare procedures for in-service inspection, for repairs that are necessitated by the inspection, and for records and reports is considered to be administrative controls. Administrative controls will provide a formal review and approval process.

In summary, corrective actions, confirmation process, and administrative controls are addressed by the applicant' s QA program as required by 10 CFR Part 50, Appendix B. No further evaluation is recommended for the applicant's 10 CFR 50, Appendix B, QA program. However, 10 CFR

Part 50, Appendix B, covers safety-related structures and components. There are non-safetyrelated structures and components subject to aging management review for license renewal.

DRAFT - 12/06/99

Thus, further evaluation is recommended for aging management programs that apply to nonsafety-related structures and components regarding corrective actions, confirmation process, and administrative controls. The applicant has an option to commit to include non-safety-related structures and components in the approved Appendix B QA Program. Any revisions to the approved QA program will be processed in accordance with 10 CFR 50.54(a). Should the applicant choose to have a separate license renewal QA program for non-safety-related structures and components, this separate program should address corrective actions, confirmation process, and administrative controls, and is subject to a case by case review by the staff.

RES REVIEW OF DRAFT GALL - 2 REPORT

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