3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 Introduction

Section 3.4 provides the results of the aging management reviews (AMRs) for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as subject to AMR. The systems or portions of systems are described in the indicated sections of the Application.

- Auxiliary Steam System (Section 2.3.4.1)
- Condensate (Auxiliary) System (Section 2.3.4.2)
- Condensate (Nuclear) System (Section 2.3.4.3)
- Main Steam System (Section 2.3.4.4)
- Main Steam Leakage Control System (Section 2.3.4.5)
- Miscellaneous Drain System (Section 2.3.4.6)
- Reactor Feedwater System (Section 2.3.4.7)

Table 3.4.1, Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801, provides the summary of the programs evaluated in NUREG-1801 that are applicable to component and commodity groups in this section. Text addressing summary items requiring further evaluation is provided in Section 3.4.2.2.

3.4.2 Results

The following tables summarize the results of the AMR for the Steam and Power Conversion Systems.

Table 3.4.2-1	Aging Management Review Results - Auxiliary Steam System
Table 3.4.2-2	Aging Management Review Results - Condensate (Auxiliary) System
Table 3.4.2-3	Aging Management Review Results - Condensate (Nuclear) System
Table 3.4.2-4	Aging Management Review Results - Main Steam System
Table 3.4.2-5	Aging Management Review Results - Main Steam Leakage Control System
Table 3.4.2-6	Aging Management Review Results - Miscellaneous Drain System
Table 3.4.2-7	Aging Management Review Results - Reactor Feedwater System

3.4.2.1 Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The materials from which specific components and commodities are fabricated, the environments to which they are exposed, the aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above systems in the following sections.

3.4.2.1.1 Auxiliary Steam System

Materials

The materials of construction for subject mechanical components of the Auxiliary Steam System are:

- Gray cast iron
- Stainless steel
- Steel

Environments

Subject mechanical components of the Auxiliary Steam System are exposed to the following normal operating environments:

- Air-indoor uncontrolled
- Air-outdoor
- Steam

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Auxiliary Steam System:

- Cracking
- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for subject mechanical components of the Auxiliary Steam System:

- Bolting Integrity Program
- BWR Water Chemistry Program

- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion (FAC) Program
- Selective Leaching Inspection

3.4.2.1.2 Condensate (Auxiliary) System

Materials

The materials of construction for subject mechanical components of the Condensate (Auxiliary) System are:

- Gray cast iron
- Steel

Environments

Subject mechanical components of the Condensate (Auxiliary) System are exposed to the following normal operating environments:

- Air-indoor uncontrolled
- Air-outdoor
- Treated water > 60 °C (140 °F)

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Condensate (Auxiliary) System:

- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for subject mechanical components of the Condensate (Auxiliary) System:

- Bolting Integrity Program
- BWR Water Chemistry Program
- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program

3.4.2.1.3 Condensate (Nuclear) System

Materials

The materials of construction for the subject mechanical components of the Condensate (Nuclear) System are:

- Cast austenitic stainless steel (CASS)
- Stainless steel
- Steel

Environments

The subject mechanical components of the Condensate (Nuclear) System are exposed to the following normal operating plant environments:

- Air-indoor uncontrolled
- Air-outdoor
- Condensation
- Moist air
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Condensate (Nuclear) System:

- Cracking
- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for the subject mechanical components of the Condensate (Nuclear) System:

- Aboveground Steel Tanks Inspection
- Bolting Integrity Program
- Buried Piping and Tanks Inspection Program
- BWR Water Chemistry Program

- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion (FAC) Program
- Supplemental Piping/Tank Inspection

3.4.2.1.4 Main Steam System

Materials

The materials of construction for subject mechanical components of the Main Steam System are:

- Aluminum
- Gray cast iron
- Stainless steel
- Steel

Environments

Subject mechanical components of the Main Steam System are exposed to the following normal operating environments:

- Air-indoor uncontrolled
- Dried air
- Moist air
- Steam
- Treated water
- Treated water > 60 °C (140 °F)

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Main Steam System:

- Cracking
- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for subject mechanical components of the Main Steam System:

- Bolting Integrity Program
- BWR Water Chemistry Program
- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion (FAC) Program
- Selective Leaching Inspection
- Supplemental Piping/Tank Inspection

3.4.2.1.5 Main Steam Leakage Control System

Materials

The materials of construction for subject mechanical components of the Main Steam Leakage Control System are:

- Gray cast iron
- Stainless steel
- Steel

Environments

Subject mechanical components of the Main Steam Leakage Control System are exposed to the following normal operating environments:

- Air-indoor uncontrolled
- Steam

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Main Steam Leakage Control System:

- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for subject mechanical components of the Main Steam Leakage Control System:

- Bolting Integrity Program
- BWR Water Chemistry Program
- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program

3.4.2.1.6 Miscellaneous Drain System

Materials

The materials of construction for subject mechanical components of the Miscellaneous Drain System are:

- Stainless steel
- Steel

Environments

Subject mechanical components of the Miscellaneous Drain System are exposed to the following normal operating environments:

- Air-indoor uncontrolled
- Moist air
- Steam

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Miscellaneous Drain System:

- Cracking
- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for subject mechanical components of the Miscellaneous Drain System:

- Bolting Integrity Program
- BWR Water Chemistry Program
- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion (FAC) Program
- Supplemental Piping/Tank Inspection

3.4.2.1.7 Reactor Feedwater System

Materials

The materials of construction for the subject mechanical components of the Reactor Feedwater System are:

- Stainless steel
- Steel

Environments

The subject mechanical components of the Reactor Feedwater System are exposed to the following normal plant operating environments:

- Air-indoor uncontrolled
- Treated water > 60 °C (140 °F)

Aging Effects Requiring Management

The following aging effects require management for the subject mechanical components of the Reactor Feedwater System:

- Cracking
- Loss of material
- Loss of pre-load

Aging Management Programs

The following aging management programs manage the aging effects for the subject mechanical components of the Reactor Feedwater System:

- Bolting Integrity Program
- BWR Water Chemistry Program
- Chemistry Program Effectiveness Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion (FAC) Program

3.4.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

For the Steam and Power Conversion systems, those items requiring further evaluation are addressed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Fatigue is a time-limited aging analysis, as defined in 10 CFR 54.3. Time-limited aging analyses are required to be evaluated in accordance with 10 CFR 54.21(c). Time-limited aging analyses identified for fatigue in the Steam and Power Conversion systems are evaluated in Section 4.3.4.

3.4.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

3.4.2.2.2.1 Piping, Piping Components, Piping Elements, Tanks, and Heat Exchangers

Loss of material due to general, pitting, and crevice corrosion for steel piping components and tanks exposed to treated water (including steam) in the Steam and Power Conversion systems is managed by the BWR Water Chemistry Program. The BWR Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. The Chemistry Program Effectiveness Inspection will provide a verification of the effectiveness of the BWR Water Chemistry Program to manage loss of material due to general, pitting, and crevice corrosion through examination of steel piping components and tanks exposed to treated water.

3.4.2.2.2.2 Piping, Piping Components, and Piping Elements – Lubricating Oil

As described in Table 3.4.1, there are no components compared to item number 3.4.1-07. There are no steel components exposed to a lubricating oil environment that are subject to AMR for the Steam and Power Conversion systems.

3.4.2.2.3 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion (MIC), and Fouling

As described in Table 3.4.1, there are no components compared to item number 3.4.1-08. There are no steel Steam and Power Conversion systems components exposed to raw water and subject to AMR

3.4.2.2.4 Reduction of Heat Transfer due to Fouling

3.4.2.2.4.1 Heat Exchanger Tubes – Treated Water

As described in Table 3.4.1, there are no components compared to item number 3.4.1-09. There are no heat exchanger tubes subject to AMR in the Steam and Power Conversion systems.

3.4.2.2.4.2 Heat Exchanger Tubes – Lubricating Oil

As described in Table 3.4.1, there are no components compared to item number 3.4.1-10. There are no heat exchanger tubes exposed to lubricating oil and subject to AMR in the Steam and Power Conversion systems.

3.4.2.2.5 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

3.4.2.2.5.1 Piping, Piping Components, and Piping Elements - Soil

Loss of material due to general, pitting, and crevice corrosion and MIC for steel piping components with coatings and buried in soil is managed by the Buried Piping and Tanks Inspection Program.

3.4.2.2.5.2 Heat Exchanger Components – Lubricating Oil

As described in Table 3.4.1, there are no components compared to item number 3.4.1-12. There are no steel heat exchanger components exposed to lubricating oil and subject to AMR in the Steam and Power Conversion systems.

3.4.2.2.6 Cracking due to Stress Corrosion Cracking (SCC)

Cracking due to SCC for stainless steel piping components exposed to treated water or steam in the Steam and Power Conversion systems is managed by the BWR Water Chemistry Program. The BWR Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. The Chemistry Program Effectiveness Inspection will provide a verification of the effectiveness of the BWR Water Chemistry Program to manage cracking due to SCC through examination of stainless steel piping components exposed to treated water or steam.

In the case of stainless steel bolting submerged in the suppression pool and exposed to treated water, the Bolting Integrity Program is credited with management of cracking.

The Bolting Integrity Program includes the periodic inspection of bolting for indications of degradation.

3.4.2.2.7 Loss of Material due to Pitting and Crevice Corrosion

3.4.2.2.7.1 Piping, Piping Components, Piping Elements, Tanks, and Heat Exchanger Components

There are no aluminum components, no copper alloy components, no stainless steel tanks, and no stainless steel heat exchanger components exposed to treated water and subject to AMR in the Steam and Power Conversion systems.

Loss of material due to pitting and crevice corrosion for stainless steel piping components and loss of material for steel tanks exposed to treated water in the Steam and Power Conversion systems is managed by the BWR Water Chemistry Program. The BWR Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. The Chemistry Program Effectiveness Inspection will provide a verification of the effectiveness of the BWR Water Chemistry Program to manage loss of material through examination of stainless steel piping components and steel tanks exposed to treated water.

In the case of stainless steel bolting exposed to treated water, the Bolting Integrity Program is credited with management of loss of material. The Bolting Integrity Program includes the periodic inspection of bolting for indications of degradation.

3.4.2.2.7.2 Piping, Piping Components, Piping Elements - Soil

As described in Table 3.4.1, there are no components compared to item number 3.4.1-17. There are no stainless steel piping components in the Steam and Power Conversion systems that are exposed to soil.

3.4.2.2.7.3 Piping, Piping Components, Piping Elements – Lubricating Oil

As described in Table 3.4.1, there are no components compared to item number 3.4.1-18. There are no copper alloy piping components exposed to lubricating oil and subject to AMR in the Steam and Power Conversion systems.

3.4.2.2.8 Loss of Material due to Pitting, Crevice, and Microbiologically Influenced Corrosion

As described in Table 3.4.1, there are no components compared to item number 3.4.1-19. There are no stainless steel piping or heat exchanger components exposed to lubricating oil and subject to AMR in the Steam and Power Conversion systems.

3.4.2.2.9 Loss of Material due to General, Pitting, Crevice, and Galvanic Corrosion

Loss of material due to general, galvanic, pitting, and crevice corrosion for steel heat exchanger components (main condenser shell) exposed to treated water in the Steam and Power Conversion systems is managed by the BWR Water Chemistry Program. The BWR Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. The Chemistry Program Effectiveness Inspection will provide a verification of the effectiveness of the BWR Water Chemistry Program to manage loss of material through examination of steel heat exchanger components exposed to treated water.

3.4.2.2.10 Quality Assurance for Aging Management of Non-safety Related Components

Quality Assurance provisions applicable to license renewal are discussed in Appendix B, Section B.1.3.

3.4.2.3 Time-Limited Aging Analyses

The time-limited aging analysis identified below are associated with the Steam and Power Conversion Systems components. The section of the application that contains the time-limited aging analysis review results is indicated in parentheses.

- Metal Fatigue (Section 4.3, Metal Fatigue)

3.4.3 Conclusions

The Steam and Power Conversion Systems components and commodities subject to AMR have been identified in accordance with 10 CFR 54.21. The aging management programs selected to manage the effects of aging for the mechanical components and commodities are identified in the following tables and Section 3.4.2.1. A description of the aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstration provided in Appendix B, the effects of aging associated with the Steam and Power Conversion Systems components and commodities will be managed so that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-01	Steel piping, piping components, and piping elements exposed to steam or treated water	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	Fatigue is a TLAA. Refer to Section 3.4.2.2.1 for further information.
3.4.1-02	Steel piping, piping components, and piping elements exposed to steam	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage loss of material for steel piping, piping components, and piping elements in the steam and power conversion systems exposed to steam. Refer to Section 3.4.2.2.2.1 for further information.
3.4.1-03	PWR Only				

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-04	Steel piping, piping components, and piping elements exposed to treated water	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage loss of material for steel piping, piping components, and piping elements in the steam and power conversion systems exposed to treated water, including treated water >60 C (140 °F). Refer to Section 3.4.2.2.2.1 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-05	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage loss of material for steel heat exchanger components of the main condenser (the waterbox, the hotwell, and the steam space) exposed to treated water. Refer to Section 3.4.2.2.9 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-06	Steel and stainless steel tanks exposed to treated water	Loss of material due to general (steel only) pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage loss of material for steel tanks in the steam and power conversion systems exposed to treated water. There are no stainless steel tanks in the steam and power conversion systems exposed to treated water. Refer to Sections 3.4.2.2.2.1 and 3.4.2.2.7.1 for further information.
3.4.1-07	Steel piping, piping components, and piping elements exposed to lubricating oil	Loss of material due to general, pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no steel piping, piping components, or piping elements in the steam and power conversion systems exposed to lubricating oil. Refer to Section 3.4.2.2.2.2 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-08	Steel piping, piping components, and piping elements exposed to raw water	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling	Plant specific	Yes, plant specific	Not applicable. There are no steel piping, piping components, or piping elements in the steam and power conversion systems exposed to raw water. Refer to Section 3.4.2.2.3 for further information.
3.4.1-09	Stainless steel and copper alloy heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no stainless steel or copper alloy heat exchanger tubes in the steam and power conversion systems exposed to treated water. Refer to Section 3.4.2.2.4.1 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-10	Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes in the steam and power conversion systems exposed to lubricating oil. Refer to Section 3.4.2.2.4.2 for further information.
3.4.1-11	Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Buried Piping and Tanks Surveillance Or Buried Piping and Tanks Inspection	No Yes, detection of aging effects and operating experience are to be further evaluated	Not applicable. The Buried Piping and Tanks Surveillance is not credited for aging management. Consistent with NUREG-1801. The Buried Piping and Tanks Inspection Program is credited to manage loss of material for buried steel piping in the steam and power conversion systems exposed to soil. Refer to Section 3.4.2.2.5.1 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-12	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no steel heat exchanger components in the steam and power conversion systems exposed to lubricating oil. Refer to Section 3.4.2.2.5.2 for further information.
3.4.1-13	Stainless steel piping, piping components, piping elements exposed to steam	Cracking due to stress corrosion cracking	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage cracking for stainless steel piping, piping components, and piping elements in the steam and power conversion systems exposed to steam. Refer to Section 3.4.2.2.6 for further information.

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
3.4.1-14	Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water >60 °C (>140 °F)	Cracking due to stress corrosion cracking	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-101. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage cracking for stainless steel piping, piping components, and piping elements in the steam and power conversion systems exposed to treated water >60 ºC (140 ºF). This item is also applied to stainless steel bolting associated with the main steam quenchers submerged in, and exposed to the treated water environment of, the suppression pool. The Bolting Integrity Program is credited to manage cracking of this bolting. A Note E is applied. Refer to Section 3.4.2.2.6 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-15	Aluminum and copper alloy piping, piping components, and piping elements exposed to treated water	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no aluminum or copper alloy piping, piping components, or piping elements in the steam and power conversion systems exposed to treated water. Refer to Section 3.4.2.2.7.1 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-16	Stainless steel piping, piping components, and piping elements; tanks, and heat exchanger components exposed to treated water	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Consistent with NUREG-1801. The BWR Water Chemistry Program, in conjunction with the Chemistry Program Effectiveness Inspection, is credited to manage loss of material for stainless steel piping, piping components, and piping elements in the steam and power conversion systems exposed to treated water, including treated water >60 C (140 °F). There are no stainless steel tanks or heat exchanger components in the steam and power conversion systems exposed to treated water. This item is also applied to stainless steel bolting associated with the main steam quenchers submerged in, and exposed to the treated water environment of, the suppression pool. The Bolting Integrity Program is credited to manage loss of material. A Note E is applied. Refer to Section 3.4.2.2.7.1 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-17	Stainless steel piping, piping components, and piping elements exposed to soil	Loss of material due to pitting and crevice corrosion	Plant specific	Yes, plant specific	Not applicable. *There are no stainless steel piping, piping components, or piping elements in the steam and power conversion systems exposed to soil.* Refer to Section 3.4.2.2.7.2 for further information.
3.4.1-18	Copper alloy piping, piping components, and piping elements exposed to lubricating oil	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and *One-Time* Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no copper alloy piping, piping components, or piping elements in the steam and power conversion systems exposed to lubricating oil. Refer to Section 3.4.2.2.7.3 for further information.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-19	Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes, detection of aging effects is to be evaluated	Not applicable. There are no stainless steel piping, piping components, piping elements, or heat exchanger components in the steam and power conversion system exposed to lubricating oil. Refer to Section 3.4.2.2.8 for further information.
3.4.1-20	Steel tanks exposed to air – outdoor (external)	Loss of material/ general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Consistent with NUREG-1801, with exceptions. The Aboveground Steel Tanks Inspection will detect and characterize loss of material where the base of the steel condensate storage tank (CST) is in contact with the tank foundation and exposed to air-outdoor. The design of the CST foundation allows potential water pooling at the bottom of the tanks due to exposure to precipitation (e.g., rain, snow). Refer also to Item Number 3.4.1-28 below.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-21	High-strength steel closure bolting exposed to air with steam or water leakage	Cracking due to cyclic loading, stress corrosion cracking	Bolting Integrity	No	Not applicable. There is no high-strength steel bolting in the steam and power conversion systems exposed to air with steam or water leakage.
3.4.1-22	Steel bolting and closure bolting exposed to air with steam or water leakage, air – outdoor (external) or air – indoor uncontrolled (external);	Loss of material due to general, pitting and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Consistent with NUREG-1801, with exceptions. The Bolting Integrity Program is credited to manage loss of material and loss of pre-load for steel bolting in the steam and power conversion systems exposed to air-indoor uncontrolled (external) or air-outdoor (external). Some bolting in the Condensate (Auxiliary) System has an external surface temperature exceeding 212 °F; therefore, loss of material is not an aging effect requiring management. A Note I is applied

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-23	Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F)	Cracking due to stress corrosion cracking	Closed-Cycle Cooling Water System	No	Not applicable. There are no stainless steel piping, piping components, or piping elements in the steam and power conversion systems exposed to closed cycle cooling water >60 C (140 ºF).
3.4.1-24	Steel heat exchanger components exposed to closed cycle cooling water	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable. There are no steel heat exchanger components in the steam and power conversion systems exposed to closed cycle cooling water.
3.4.1-25	Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable. There are no stainless steel piping, piping components, piping elements, or heat exchanger components in the steam and power conversion systems exposed to closed cycle cooling water.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-26	Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable. There are no copper alloy piping, piping components, or piping elements in the steam and power conversion systems exposed to closed cycle cooling water.
3.4.1-27	Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed cycle cooling water	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes in the steam and power conversion systems exposed to closed cycle cooling water.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-28	Steel external surfaces exposed to air – indoor uncontrolled (external), condensation (external) or air outdoor (external)	Loss of material due to general corrosion	External Surfaces Monitoring	No	Consistent with NUREG-1801. Except as noted below, the External Surfaces Monitoring Program is credited to manage loss of material for steel external surfaces in the steam and power conversion systems exposed to air-indoor uncontrolled (external), condensation (external) or air-outdoor (external). This includes the external surfaces of each CST not in contact with the tank foundation (refer to Item Number 3.4.1-20). This item is also applied to steel turbine casings exposed to air-indoor uncontrolled (external); and to steel internal surfaces exposed to air-indoor uncontrolled (internal) where it has been demonstrated that the internal environment is the same as the external environment. The External Surfaces Monitoring Program is credited. A Note C is applied in these cases.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-28 (cont'd)					This item is also applied to air-water interfaces for steel components that penetrate the surface of the suppression pool (subject to alternate wetting and drying). The Supplemental Piping/Tank Inspection is credited to detect and characterize loss of material. A Note E is applied. This item is also applied to steel bolting exposed to condensation (external). The Bolting Integrity Program is credited to manage loss of material. A Note E is applied. This item is also applied to steel piping from each CST that is enclosed in a guard pipe, which is evaluated as exposed to an air-indoor uncontrolled (external) environment. The guard pipe is buried. The Buried Piping and Tanks Inspection Program is credited to manage loss of material. A Note E is applied.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-28 (cont'd)					The temperatures of some steel external surfaces exposed to air-indoor uncontrolled (external) in the Condensate (Auxiliary) System exceed 212 °F; therefore, loss of material is not an aging effect requiring management. A Note I is applied.
3.4.1-29	Steel piping, piping components, and piping elements exposed to steam or treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Consistent with NUREG-1801. The Flow-Accelerated Corrosion (FAC) Program is credited to manage loss of material (wall thinning) due to FAC for steel piping, piping components, and piping elements in the steam and power conversion systems exposed to steam or treated water, including treated water >60 C (140 °F). This item is also applied to the main condenser shell and the high-pressure turbine casing, which are exposed to treated water and steam, respectively. The Flow-Accelerated Corrosion (FAC) Program is credited. A Note C is applied.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-30	Steel piping, piping components, and piping elements exposed to air outdoor (internal) or condensation (internal)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	This item is applied to steel piping in the Condensate (Nuclear) System exposed to air-outdoor (internal). The External Surfaces Monitoring Program is credited to manage loss of material. A Note E is applied.
3.4.1-31	Steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice, galvanic, and microbiologically influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable. There are no steel heat exchanger components in the steam and power conversion systems exposed to raw water.
3.4.1-32	Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable. There are no stainless steel or copper alloy piping, piping components, or piping elements in the steam and power conversion systems exposed to raw water.
3.4.1-33	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice, and microbiologically influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable. There are no stainless steel heat exchanger components in the steam and power conversion systems exposed to raw water.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-34	Steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes in the steam and power conversion systems exposed to raw water.
3.4.1-35	Copper alloy >15% Zn piping, piping components, and piping elements exposed to closed cycle cooling water, raw water or treated water	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable. There are no copper alloy >15% Zn piping, piping components, or piping elements in the steam and power conversion systems exposed to closed cycle cooling water, raw water, or treated water.
3.4.1-36	Gray cast iron piping, piping components, and piping elements exposed to soil, treated water or raw water	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable. There are no gray cast iron piping, piping components, or piping elements in the steam and power conversion systems exposed to soil, treated water, or raw water.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-37	Steel, stainless steel, and nickel-based alloy piping, piping components, and piping elements exposed to steam	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Consistent with NUREG-1801. The BWR Water Chemistry Program is credited to manage loss of material for steel and stainless steel piping, piping components, and piping elements in the steam and power conversion systems exposed to steam. There are no nickel-based alloy piping, piping components, and piping elements in the steam and power conversion systems exposed to steam. Additionally, the Chemistry Program Effectiveness Inspection is credited to verify the effectiveness of the BWR Water Chemistry Program. A Note E is applied. This item is applied to the high-pressure turbine casing (MS-DT-HP) exposed to steam. A Note C is applied.
3.4.1-38	PWR Only				
3.4.1-39	PWR Only				

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-40	Glass piping elements exposed to air, lubricating oil, raw water, and treated water	None	None	NA - No AEM or AMP	Not applicable. There are no glass piping elements in the steam and power conversion systems exposed to air, lubricating oil, raw water, or treated water.
3.4.1-41	Stainless steel, copper alloy, and nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external)	None	None	NA - No AEM or AMP	Consistent with NUREG-1801. No aging effects were identified for stainless steel or copper alloy piping, piping components, or piping elements in the steam and power conversion systems exposed to air-indoor uncontrolled (external). This item is also applied to stainless steel internal surfaces exposed to air-indoor uncontrolled (internal) where it has been demonstrated that the internal environment is the same as the external environment. This item is also applied to stainless steel bolting exposed to air-indoor uncontrolled (external). A Note C is applied.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-42	Steel piping, piping components, and piping elements exposed to air – indoor controlled (external)	None	None	NA - No AEM or AMP	Not applicable. There are no steel piping, piping components, or piping elements in the steam and power conversion systems exposed to air-indoor controlled (external). All air-indoor environments were conservatively evaluated as uncontrolled environments.
3.4.1-43	Steel and stainless steel piping, piping components, and piping elements in concrete	None	None	NA - No AEM or AMP	Not applicable. There are no steel or stainless steel piping, piping components, or piping elements in the steam and power conversion systems embedded in concrete.
3.4.1-44	Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas	None	None	NA - No AEM or AMP	Consistent with NUREG-1801. This item is applied to aluminum and stainless steel piping components in steam and power conversion systems exposed to dried air. Dried air is not an environment in NUREG-1801 Chapter VIII for aluminum or stainless steel; however, gas is evaluated as an equivalent environment.

Table 3.4.2-1 Aging Management Review Results – Auxiliary Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
2	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
3	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
4	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
5	Bolting	Structural integrity	Steel	Air-outdoor (External)	Loss of material	Bolting Integrity	VIII.H-1	3.4.1-22	B
6	Bolting	Structural integrity	Steel	Air-outdoor (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	H
7	Piping	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
8	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A
9	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A

Table 3.4.2-1			Aging Management Review Results – Auxiliary Steam System						
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
10	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
11	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
12	Piping	Structural integrity	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
13	Strainer Body	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A
14	Strainer Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A
15	Strainer Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
16	Strainer Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
17	Strainer Body	Structural integrity	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
18	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A

Table 3.4.2-1 Aging Management Review Results – Auxiliary Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
19	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A
20	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
21	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Selective Leaching Inspection	N/A	N/A	G
22	Trap Body	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
23	Trap Body	Structural integrity	Gray Cast Iron	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
24	Trap Body	Structural integrity	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
25	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A
26	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A
27	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A

Table 3.4.2-1 Aging Management Review Results – Auxiliary Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
28	Trap Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
29	Tubing	Structural integrity	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A
30	Tubing	Structural integrity	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
31	Tubing	Structural integrity	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
32	Tubing	Structural integrity	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
33	Tubing	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
34	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A
35	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A
36	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A

Table 3.4.2-1				Aging Management Review Results – Auxiliary Steam System					
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
37	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
38	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-4	3.4.1-02	A
39	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-4	3.4.1-02	A
40	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
41	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
42	Valve Body	Structural integrity	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A

Table 3.4.2-2			Aging Management Review Results – *Condensate (Auxiliary)* System						
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	None	None	VIII.H-4	3.4.1-22	I 0406
2	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
3	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
4	Bolting	Structural integrity	Steel	Air-outdoor (External)	Loss of material	Bolting Integrity	VIII.H-1	3.4.1-22	B
5	Bolting	Structural integrity	Steel	Air-outdoor (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	H
6	Condenser (CO-CU-1)	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
7	Condenser (CO-CU-1)	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
8	Piping	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
9	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-2 Aging Management Review Results – Condensate (Auxiliary) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
10	Piping	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
11	Piping	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A
12	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	None	None	VIII.H-7	3.4.1-28	I 0406
13	Piping	Structural integrity	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
14	Pump Casing (CO-P-4)	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
15	Pump Casing (CO-P-4)	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
16	Valve Body	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
17	Valve Body	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A

Table 3.4.2-2 Aging Management Review Results – Condensate (Auxiliary) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
18	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	None	None	VIII.H-7	3.4.1-28	I 0406
19	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
20	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
2	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
3	Bolting	Pressure boundary	Steel	Air-outdoor (External)	Cracking	Bolting Integrity	N/A	N/A	H 0407
4	Bolting	Pressure boundary	Steel	Air-outdoor (External)	Loss of material	Bolting Integrity	VIII.H-1	3.4.1-22	B
5	Bolting	Pressure boundary	Steel	Air-outdoor (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	H
6	Bolting	Pressure boundary	Steel	Condensation (External)	Cracking	Bolting Integrity	N/A	N/A	H
7	Bolting	Pressure boundary	Steel	Condensation (External)	Loss of material	Bolting Integrity	VIII.H-10	3.4.1-28	E
8	Bolting	Pressure boundary	Steel	Condensation (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	H
9	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B

Table 3.4.2-3	Aging Management Review Results – Condensate (Nuclear) System								
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
10	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
11	Bolting	Structural integrity	Steel	Condensation (External)	Cracking	Bolting Integrity	N/A	N/A	H
12	Bolting	Structural integrity	Steel	Condensation (External)	Loss of material	Bolting Integrity	VIII.H-10	3.4.1-28	E
13	Bolting	Structural integrity	Steel	Condensation (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	H
14	Heat Exchanger (shell), Main Condenser COND-HX-9	Pressure boundary	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
15	Heat Exchanger (shell), Main Condenser COND-HX-9	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.E-35	3.4.1-29	C
16	Heat Exchanger (shell), Main Condenser COND-HX-9	Pressure boundary	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-7	3.4.1-05	A

Table 3.4.2-3			Aging Management Review Results – Condensate (Nuclear) System						
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
17	Heat Exchanger (shell), Main Condenser COND-HX-9	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-7	3.4.1-05	A
18	Heat Exchanger (shell), Main Condenser COND-HX-9	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
19	Orifice	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
20	Orifice	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
21	Orifice	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
22	Orifice	Pressure boundary	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G
23	Orifice	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
24	Orifice	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A

Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
25	Orifice	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
26	Orifice	Structural integrity	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G
27	Orifice	Throttling	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
28	Orifice	Throttling	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
29	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
30	Piping	Pressure boundary	Steel	Air-outdoor (Internal)	Loss of material	External Surfaces Monitoring	VIII.B1-6	3.4.1-30	E
31	Piping	Pressure boundary	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
32	Piping	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A
33	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Buried Piping and Tanks Inspection	VIII.H-7	3.4.1-28	E 0408

Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
34	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
35	Piping	Pressure boundary	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
36	Piping	Pressure boundary	Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	VIII.H-10	3.4.1-28	A
37	Piping	Pressure boundary	Steel	Soil (External)	Loss of material	Buried Piping and Tanks Inspection	VIII.E-1	3.4.1-11	A
38	Piping	Structural integrity	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410
39	Piping	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
40	Piping	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
41	Piping	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
42	Piping	Structural integrity	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G

Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
43	Piping	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
44	Piping	Structural integrity	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
45	Piping	Structural integrity	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A
46	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
47	Piping	Structural integrity	Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	VIII.H-10	3.4.1-28	A
48	Pump Casing (COND-P-3, 4, 5)	Structural integrity	Cast Austenitic Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
49	Pump Casing (COND-P-3, 4, 5)	Structural integrity	Cast Austenitic Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
50	Pump Casing (COND-P-3, 4, 5)	Structural integrity	Cast Austenitic Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A

Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
51	Pump Casing (COND-P-3, 4, 5)	Structural integrity	Cast Austenitic Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G
52	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Air-outdoor (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	C 0411
53	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
54	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-40	3.4.1-06	A
55	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-40	3.4.1-06	A
56	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Air-outdoor (External)	Loss of material	Aboveground Steel Tanks Inspection	VIII.E-39	3.4.1-20	B 0409
57	Tank (COND-TK-1A, 1B)	Pressure boundary	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
58	Tubing	Pressure boundary	Stainless Steel	Air-outdoor (Internal)	None	None	N/A	N/A	G
59	Tubing	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Table 3.4.2-3 Aging Management Review Results – Condensate (Nuclear) System									
60	Tubing	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
61	Tubing	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
62	Tubing	Pressure boundary	Stainless Steel	Air-outdoor (External)	None	None	N/A	N/A	G
63	Tubing	Pressure boundary	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	VII.F2-1	3.3.1-27	E
64	Tubing	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
65	Tubing	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A
66	Tubing	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
67	Tubing	Structural integrity	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G
68	Valve Body	Pressure boundary	Stainless Steel	Air-outdoor (Internal)	None	None	N/A	N/A	G

Table 3.4.2-3	Aging Management Review Results – Condensate (Nuclear) System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
69	Valve Body	Pressure boundary	Stainless Steel	Air-outdoor (External)	None	None	N/A	N/A	G
70	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
71	Valve Body	Pressure boundary	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
72	Valve Body	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A
73	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
74	Valve Body	Pressure boundary	Steel	Air-outdoor (External)	Loss of material	External Surfaces Monitoring	VIII.H-8	3.4.1-28	A
75	Valve Body	Pressure boundary	Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	VIII.H-10	3.4.1-28	A
76	Valve Body	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-29	3.4.1-16	A
77	Valve Body	Structural integrity	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-29	3.4.1-16	A

Table 3.4.2-3	Aging Management Review Results – Condensate (Nuclear) System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
78	Valve Body	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
79	Valve Body	Structural integrity	Stainless Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	N/A	N/A	G
80	Valve Body	Structural integrity	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.E-33	3.4.1-04	A
81	Valve Body	Structural integrity	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.E-33	3.4.1-04	A
82	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
83	Valve Body	Structural integrity	Steel	Condensation (External)	Loss of material	External Surfaces Monitoring	VIII.H-10	3.4.1-28	A

Table 3.4.2-4 Aging Management Review Results – Main Steam System									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Bolting	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	C
2	Bolting	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	F
3	Bolting	Pressure boundary	Stainless Steel	Treated water (External)	Cracking	Bolting Integrity	VIII.C-2	3.4.1-14	E 0405
4	Bolting	Pressure boundary	Stainless Steel	Treated water (External)	Loss of pre-load	Bolting Integrity	N/A	N/A	F
5	Bolting	Pressure boundary	Stainless Steel	Treated water (External)	Loss of material	Bolting Integrity	VIII.C-1	3.4.1-16	E 0405
6	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
7	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
8	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
9	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B

Table 3.4.2-4			Aging Management Review Results – Main Steam System						
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
10	Manifold	Pressure boundary	Aluminum	Dried air (Internal)	None	None	VIII.I-1	3.4.1-44	A 0402
11	Manifold	Pressure boundary	Aluminum	Air-indoor uncontrolled (External)	None	None	N/A	N/A	G
12	Moisture Separator	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	C
13	Moisture Separator	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
14	Moisture Separator	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	C
15	Moisture Separator	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
16	Orifice	Structural integrity	Stainless Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
17	Orifice	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
18	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A

Table 3.4.2-4	Aging Management Review Results – Main Steam System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
19	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
20	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
21	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
22	Piping	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	BWR Water Chemistry	VIII.C-2	3.4.1-14	A
23	Piping	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.C-2	3.4.1-14	A
24	Piping	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-4	3.4.1-16	A 0403
25	Piping	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-4	3.4.1-16	A 0403
26	Piping	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410

Table 3.4.2-4 Aging Management Review Results – Main Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
27	Piping	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
28	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
29	Piping	Pressure boundary	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
30	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A
31	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
32	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
33	Piping	Pressure boundary	Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-6	3.4.1-04	A
34	Piping	Pressure boundary	Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-6	3.4.1-04	A
35	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-4		Aging Management Review Results – Main Steam System							
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
36	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Supplemental Piping/Tank Inspection	VIII.H-7	3.4.1-28	E 0401
37	Piping	Pressure boundary	Steel	Treated water (External)	Loss of material	BWR Water Chemistry	VIII.B2-6	3.4.1-04	A
38	Piping	Pressure boundary	Steel	Treated water (External)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-6	3.4.1-04	A
39	Piping	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
40	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A
41	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
42	Piping	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
43	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
44	Piping	Structural integrity	Stainless Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G

Table 3.4.2-4 Aging Management Review Results – Main Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
45	Quencher	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.C-1	3.4.1-16	A
46	Quencher	Pressure boundary	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-1	3.4.1-16	A
47	Quencher	Pressure boundary	Stainless Steel	Treated water (External)	Loss of material	BWR Water Chemistry	VIII.C-1	3.4.1-16	A
48	Quencher	Pressure boundary	Stainless Steel	Treated water (External)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-1	3.4.1-16	A
49	Quencher	Spray	Stainless Steel	Treated water (Internal)	Loss of material	BWR Water Chemistry	VIII.C-1	3.4.1-16	A
50	Quencher	Spray	Stainless Steel	Treated water (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-1	3.4.1-16	A
51	Quencher	Spray	Stainless Steel	Treated water (External)	Loss of material	BWR Water Chemistry	VIII.C-1	3.4.1-16	A
52	Quencher	Spray	Stainless Steel	Treated water (External)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-1	3.4.1-16	A
53	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A

Table 3.4.2-4 Aging Management Review Results – Main Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
54	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
55	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
56	Strainer Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
57	Trap Body	Structural integrity	Gray Cast Iron	Moist air (Internal)	Loss of material	Selective Leaching Inspection	N/A	N/A	G
58	Trap Body	Structural integrity	Gray Cast Iron	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
59	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A
60	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
61	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
62	Trap Body	Structural integrity	Gray Cast Iron	Steam (Internal)	Loss of material	Selective Leaching Inspection	N/A	N/A	G

Table 3.4.2-4			Aging Management Review Results – Main Steam System						
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
63	Trap Body	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
64	Trap Body	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
65	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A
66	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
67	Trap Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
68	Trap Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
69	Tubing	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410
70	Tubing	Pressure boundary	Stainless Steel	Dried air (Internal)	None	None	VIII.I-12	3.4.1-44	A 0402
71	Tubing	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A

Table 3.4.2-4 Aging Management Review Results – Main Steam System									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
72	Tubing	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
73	Tubing	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
74	Tubing	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
75	Tubing	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	BWR Water Chemistry	VIII.C-2	3.4.1-14	A
76	Tubing	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.C-2	3.4.1-14	A
77	Tubing	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-4	3.4.1-16	A 0403
78	Tubing	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-4	3.4.1-16	A 0403
79	Tubing	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A

Table 3.4.2-4			Aging Management Review Results – Main Steam System						
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
80	Turbine Casing	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	C
81	Turbine Casing	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
82	Turbine Casing	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	C
83	Turbine Casing	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
84	Valve Body	Pressure boundary	Aluminum	Dried air (Internal)	None	None	VIII.I-1	3.4.1-44	A 0402
85	Valve Body	Pressure boundary	Aluminum	Air-indoor uncontrolled (External)	None	None	N/A	N/A	G
86	Valve Body	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A
87	Valve Body	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
88	Valve Body	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A

Table 3.4.2-4 Aging Management Review Results – Main Steam System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
89	Valve Body	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
90	Valve Body	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	BWR Water Chemistry	VIII.C-2	3.4.1-14	A
91	Valve Body	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.C-2	3.4.1-14	A
92	Valve Body	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-4	3.4.1-16	A 0403
93	Valve Body	Pressure boundary	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-4	3.4.1-16	A 0403
94	Valve Body	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
95	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
96	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A

Table 3.4.2-4 Aging Management Review Results – Main Steam System									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
97	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
98	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
99	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
100	Valve Body	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
101	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-3	3.4.1-37	A
102	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-3	3.4.1-37	E
103	Valve Body	Structural integrity	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.B2-4	3.4.1-29	A
104	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-5	Aging Management Review Results – Main Steam Leakage Control System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Annubar	Structural integrity	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410
2	Annubar	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
3	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
4	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
5	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
6	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
7	Fan Housing	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
8	Fan Housing	Structural integrity	Gray Cast Iron	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
9	Filter Housing	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404

Table 3.4.2-5	Aging Management Review Results – Main Steam Leakage Control System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
10	Filter Housing	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
11	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
12	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-3	3.4.1-02	A
13	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-3	3.4.1-02	A
14	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
15	Piping	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
16	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
17	Piping	Structural integrity	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410
18	Piping	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A

Table 3.4.2-5	Aging Management Review Results – Main Steam Leakage Control System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
19	Tubing	Structural integrity	Stainless Steel	Air-indoor uncontrolled (Internal)	None	None	VIII.I-10	3.4.1-41	A 0410
20	Tubing	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
21	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
22	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-3	3.4.1-02	A
23	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-3	3.4.1-02	A
24	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
25	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	C 0404
26	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

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Table 3.4.2-6		Aging Management Review Results – Miscellaneous Drain System							
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
2	Bolting	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
3	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
4	Bolting	Structural Integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
5	Orifice	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A
6	Orifice	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
7	Orifice	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
8	Orifice	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
9	Orifice	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A

Table 3.4.2-6 Aging Management Review Results – Miscellaneous Drain System									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
10	Orifice	Structural integrity	Stainless Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
11	Orifice	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
12	Orifice	Throttling	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A
13	Orifice	Throttling	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
14	Orifice	Throttling	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
15	Orifice	Throttling	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
16	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-3	3.4.1-02	A
17	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-3	3.4.1-02	A
18	Piping	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Table 3.4.2-6 Aging Management Review Results – Miscellaneous Drain System									
19	Piping	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
20	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	BWR Water Chemistry	VIII.B2-1	3.4.1-13	A
21	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.B2-1	3.4.1-13	A
22	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.B2-2	3.4.1-37	A
23	Piping	Pressure boundary	Stainless Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.B2-2	3.4.1-37	E
24	Piping	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
25	Piping	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
26	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
27	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-3	3.4.1-02	A

Table 3.4.2-6	Aging Management Review Results – Miscellaneous Drain System								
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
28	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-3	3.4.1-02	A
29	Strainer Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
30	Strainer Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
31	Strainer Body	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
32	Strainer Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
33	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	BWR Water Chemistry	VIII.C-3	3.4.1-02	A
34	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.C-3	3.4.1-02	A
35	Valve Body	Pressure boundary	Steel	Steam (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.C-5	3.4.1-29	A
36	Valve Body	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-6 Aging Management Review Results – Miscellaneous Drain System									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
37	Valve Body	Structural integrity	Steel	Moist air (Internal)	Loss of material	Supplemental Piping/Tank Inspection	N/A	N/A	G
38	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Table 3.4.2-7 Aging Management Review Results – Reactor Feedwater System									
Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	Bolting Integrity	VIII.H-4	3.4.1-22	B
2	Bolting	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of pre-load	Bolting Integrity	VIII.H-5	3.4.1-22	B
3	Flow Element	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-7	3.4.1-04	A 0403
4	Flow Element	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-7	3.4.1-04	A 0403
5	Flow Element	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.D2-8	3.4.1-29	A 0403
6	Flow Element	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
7	Piping	Structural integrity	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	BWR Water Chemistry	VIII.E-31	3.4.1-14	A
8	Piping	Structural integrity	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Cracking	Chemistry Program Effectiveness Inspection	VIII.E-31	3.4.1-14	A

Table 3.4.2-7 Aging Management Review Results – Reactor Feedwater System

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
9	Piping	Structural integrity	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-4	3.4.1-16	A 0403
10	Piping	Structural integrity	Stainless Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-4	3.4.1-16	A 0403
11	Piping	Structural integrity	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VIII.I-10	3.4.1-41	A
12	Piping	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-7	3.4.1-04	A 0403
13	Piping	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-7	3.4.1-04	A 0403
14	Piping	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.D2-8	3.4.1-29	A 0403
15	Piping	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A
16	Valve Body	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	BWR Water Chemistry	VIII.D2-7	3.4.1-04	A 0403

Table 3.4.2-7	Aging Management Review Results – Reactor Feedwater System								
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
17	Valve Body	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Chemistry Program Effectiveness Inspection	VIII.D2-7	3.4.1-04	A 0403
18	Valve Body	Structural integrity	Steel	Treated water > 60 °C (140 °F) (Internal)	Loss of material	Flow-Accelerated Corrosion (FAC)	VIII.D2-8	3.4.1-29	A 0403
19	Valve Body	Structural integrity	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VIII.H-7	3.4.1-28	A

Generic Notes:	
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-Specific Notes:	
0401	The Supplemental Piping/Tank Inspection will manage loss of material at the air-water interface on and within the MSRV discharge piping at the surface of the suppression pool.
0402	"Dried air" is not an environment in NUREG-1801 Chapter VIII for aluminum or stainless steel; however, for the purposes of this comparison, "Gas" is an equivalent environment.
0403	"Loss of material" is not an aging effect identified in NUREG-1801 for stainless steel exposed to "Treated water > 60 °C (140 °F);" however, loss of material is not dependent on temperature in a treated water environment, so for the purposes of this comparison, "Treated water" is an equivalent environment.

Plant-Specific Notes:	
0404	The aging effect determination for the Air-indoor uncontrolled (Internal) environment is the same as the NUREG-1801 determination for an Air-indoor uncontrolled (External) environment because the material is the same and the internal environment is equivalent to the external environment evaluated in the NUREG-1801 item Monitoring of the external surface condition will be used to characterize the aging effects on the internal surfaces.
0405	Bolting associated with the quenchers is stainless steel and located in the suppression pool.
0406	This steel component has an external surface temperature > 212 °F. Therefore, the surface is dry and general corrosion is not an aging effect requiring management; there are also no other aging effects requiring management.
0407	The Bolting Integrity Program will also manage cracking for the carbon and low-alloy (steel) bolting at the base and foundation of the CSTs due to potential for ponding or pooling of water.
0408	The Buried Piping and Tanks Inspection Program will manage loss of material for the carbon steel (steel) piping from the CSTs that is enclosed in guard pipe and buried.
0409	The Aboveground Steel Tanks Inspection will detect and characterize loss of material at the base of each CST in contact with the tank foundation.
0410	The aging effect determination for the Air-indoor uncontrolled (Internal) environment is the same as the NUREG-1801 determination for an Air-indoor uncontrolled (External) environment because the material is the same and the internal environment is equivalent to the external environment evaluated in the NUREG-1801 item There are no aging effects requiring management.
0411	The aging effect determination for the Air-outdoor (Internal) environment is the same as the NUREG-1801 determination for an Air-outdoor (External) environment because the material is the same and the internal environment is equivalent to the external environment evaluated in the NUREG-1801 item. Monitoring of the external surface condition will be used to characterize the aging effects on the internal surfaces.

3.5 AGING MANAGEMENT OF CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

3.5.1 Introduction

Section 3.5 provides the results of the aging management reviews (AMRs) for those structural components and commodities identified in Section 2.4, Scoping and Screening Results - Structures, subject to AMR. The structures or structural commodities are described in the indicated sections.

- Primary Containment [Includes Drywell, Suppression Chamber, and internal structural components] (Section 2.4.1)
- Reactor Building [Includes Secondary Containment, Reactor Cavity, Refueling Area, New Fuel Storage Vault, Release Stack] (Section 2.4.2)
- Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B (Section 2.4.3)
- Circulating Water Pump House (Section 2.4.4)
- Diesel Generator Building (Section 2.4.5)
- Fresh Air Intake Structure No. 1 and 2 (Section 2.4.6)
- Makeup Water Pump House (Section 2.4.7)
- Radwaste Control Building (Section 2.4.8)
- Service Building (Section 2.4.9)
- Turbine Generator Building (Section 2.4.10)
- Water Filtration Building (Section 2.4.11)
- Yard Structures (Section 2.4.12)
- Bulk Commodities (Section 2.4.13)

Table 3.5.1, Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801, provides the summary of the programs evaluated in NUREG-1801 that are applicable to structural component and commodity groups in this section. Text addressing summary items requiring further evaluation is provided in Section 3.5.2.2.

3.5.2 Results

The following tables summarize the results of the AMR for Containments, Structures, and Component Supports.

3.5.2.1 Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The materials from which specific components and commodities are fabricated, the environments to which they are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each of the above structures and structural components in the following sections.

3.5.2.1.1 Primary Containment

Materials

Primary Containment structural components subject to AMR are constructed of the following materials:

- Aluminum
- Carbon Steel

- Concrete
- Elastomer
- Galvanized Steel
- Stainless Steel

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Primary Containment structural components subject to AMR are exposed to the following environments:

- Concrete
- Air-indoor
- Treated water
- Raw water

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Primary Containment structural components requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Primary Containment structural components:

- Inservice Inspection (ISI) Program – IWE
- Inservice Inspection (ISI) Program – IWF
- Appendix J Program
- Structures Monitoring Program
- BWR Water Chemistry Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.2 Reactor Building

Materials

Reactor Building structural components subject to AMR are constructed of the following materials:

- Aluminum
- Carbon Steel
- Concrete
- Concrete Block or Brick (freestanding or stacked shield wall)
- Galvanized Steel
- Stainless Steel
- Boron Carbide (B4C)

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Reactor Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor
- Treated water
- Raw water

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Reactor Building structural components requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Reactor Building structural components:

- Structures Monitoring Program
- Material Handling System Inspection Program
- BWR Water Chemistry Program
- Fire Protection Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.3 Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B

Materials

Standby Service Water Pump House and Spray Pond structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Concrete
- Galvanized Steel
- Stainless Steel
- Teflon

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Standby Service Water Pump House and Spray Pond structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor
- Water-flowing
- Raw water

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effects associated with the Standby Service Water Pump House and Spray Pond structural components require management:

- Cracking
- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Standby Service Water Pump House and Spray Pond structural components:

- Structures Monitoring Program – Water Control Structures Inspection
- Inservice Inspection (ISI) Program – IWF

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.4 Circulating Water Pump House

Materials

Circulating Water Pump House structural components subject to AMR constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Stainless Steel
- Concrete
- Concrete Block

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Circulating Water Pump House structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor

- Air-outdoor
- Water-flowing

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effects associated with the Circulating Water Pump House structural components, require management:

- Cracking
- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Circulating Water Pump House structural components:

- Structures Monitoring Program – Water Control Structures Inspection
- Structures Monitoring Program – Masonry Wall Inspection
- Fire Protection Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.5 Diesel Generator Building

Materials

Diesel Generator Building structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Concrete

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Diesel Generator Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Diesel Generator Building structural components, requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Diesel Generator Building structural components:

- Structures Monitoring Program
- Fire Protection Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.6 Fresh Air Intake Structure No. 1 and 2

Materials

Fresh Air Intake Structure No. 1 and 2 structural components subject to AMR are constructed of the following material:

- Concrete

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Fresh Air Intake Structure No. 1 and 2 structural components subject to AMR are exposed to the following environments:

- Soil
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

There are no aging effects requiring management for the Fresh Air Intake Structure No. 1 and 2 structural components. However, the aging management program identified below will be used to confirm the absence of significant aging effects for the period of extended operation.

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following program is credited for managing the effects of aging on the Fresh Air Intake Structure No. 1 and 2 structural components:

- Structures Monitoring Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.7 Makeup Water Pump House

Materials

Makeup Water Pump House structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Concrete

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Makeup Water Pump House structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Makeup Water Pump House structural components, requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following program is credited for managing the effects of aging on the Makeup Water Pump House structural components:

- Structures Monitoring Program – Water Control Structures Inspection

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.8 Radwaste Control Building

Materials

Radwaste Control Building structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Stainless Steel
- Concrete
- Concrete Block

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Radwaste Control Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effects associated with the Radwaste Control Building structural components, require management:

- Change in material properties
- Cracking
- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Radwaste Control Building structural components:

- Structures Monitoring Program
- Structures Monitoring Program – Masonry Wall Inspection
- Fire Protection Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.9 Service Building

Materials

Service Building structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel

- Concrete

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Service Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Service Building structural components, requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following program is credited for managing the effects of aging on the Service Building structural components:

- Structures Monitoring Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.10 Turbine Generator Building

Materials

Turbine Generator Building structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Stainless Steel

- Concrete
- Concrete Block
- Concrete Block or Brick (freestanding or stacked shield wall)

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Turbine Generator Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor
- Raw water

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effects associated with the Turbine Generator Building structural components, require management:

- Cracking
- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following programs are credited for managing the effects of aging on the Turbine Generator Building structural components:

- Structures Monitoring Program
- Structures Monitoring Program – Masonry Wall Inspection
- Fire Protection Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.11 Water Filtration Building

Materials

Water Filtration Building structural components subject to AMR are constructed of the following materials:

- Carbon Steel
- Galvanized Steel
- Concrete

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Water Filtration Building structural components subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effect associated with the Water Filtration Building structural components, requires management:

- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following program is credited for managing the effects of aging on the Water Filtration Building structural components:

- Structures Monitoring Program

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.12 Yard Structures

Materials

Structural components of yard structures subject to AMR are constructed of the following materials:

- Aluminum
- Carbon Steel
- Galvanized Steel
- Concrete
- Earthen Structures

Materials for bulk commodity components are addressed in Section 3.5.2.1.13.

Environments

Structural components of yard structures subject to AMR are exposed to the following environments:

- Soil
- Air-indoor
- Air-outdoor
- Raw water
- Water-flowing

Environments for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Effects Requiring Management

The following aging effects associated with structural components of evaluated yard structures require management:

- Cracking
- Loss of form
- Loss of material

Aging effects requiring management for bulk commodity components are addressed in Section 3.5.2.1.13.

Aging Management Programs

The following program is credited for managing the effects of aging on yard structures' structural components:

- Structures Monitoring Program
- Structures Monitoring Program – Water Control Structures Inspection

Aging management programs for bulk commodity components are addressed in Section 3.5.2.1.13.

3.5.2.1.13 Bulk Commodities

Materials

Structural components of bulk commodities subject to AMR are constructed of the following materials:

- Aluminum
- Carbon Steel
- Concrete
- Elastomer
- Fire Barrier materials (Ceramic fiber/ Thermolag/ Darmatt/ 3M Interam)
- Fluoropolymer
- Galvanized Steel
- Insulation materials (Calcium Silicate/ Fiberglass/Aluminum jacketing/ Stainless Steel Mirror insulation)
- Lubrite
- Nylon
- Stainless Steel

Environments

Structural components of bulk commodities subject to AMR are exposed to the following environments:

- Air-indoor
- Air-outdoor
- Raw water
- Soil

- Treated water

Aging Effects Requiring Management

The following aging effects associated with structural components of evaluated bulk commodities require management:

- Change in material properties
- Cracking/delamination
- Loss of material
- Separation

Aging Management Programs

The following program is credited for managing the effects of aging on bulk commodities:

- BWR Water Chemistry Program
- Fire Protection Program
- Inservice Inspection (ISI) Program – IWF
- Structures Monitoring Program

3.5.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

For the Columbia containment, structures, and component supports, those items requiring further evaluation are addressed in the following sections.

3.5.2.2.1 PWR and BWR Containments

3.5.2.2.1.1 Aging of Inaccessible Concrete Areas

The Primary Containment is a free-standing steel pressure vessel. It utilizes the pressure suppression technique through the GE BWR Mark II over-under configuration. The concrete mat foundation under the suppression chamber is a common foundation supporting the steel primary containment vessel, including all equipment and structures therein, and the Reactor Building of which the primary containment vessel is a part. The primary containment vessel and the Reactor Building enclosing the primary containment vessel are both supported on a common, reinforced concrete mat foundation.

The Reactor Building foundation mat is not subject to flowing water. Seismic Category I structures and safety-related systems and components at Columbia are located above the present groundwater elevation 380 feet msl (mean sea level) and are not subject to any force effects of buoyancy and static water from this groundwater elevation. The bottom of the Reactor Building foundation mat is at elevation 400 feet 9 inches; therefore, foundation interaction with groundwater is unlikely.

The below-grade environment at Columbia is non-aggressive (Chlorides < 500 ppm, Sulfates < 1,500 ppm, and pH > 5.5) and has been confirmed by water chemistry analysis results. Sampling results indicate a groundwater pH minimum value of 6.9, chloride content maximum value of 36 ppm, and sulfate content maximum value of 323 ppm.

Primary Containment foundation concrete is designed in accordance with American Concrete Institute (ACI) 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and American Society for Testing and Materials (ASTM) standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

The Primary Containment concrete is not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding aggressive chemical attack and embedded steel corrosion aging mechanisms.

Therefore, increases in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable for Primary Containment concrete in inaccessible areas.

The absence of concrete aging effects is confirmed under the Structures Monitoring Program. The Inservice Inspection Program –IWL does not apply to Columbia since it is a BWR Mark II steel containment.

3.5.2.2.1.2 Cracks and Distortion due to Increased Stress Levels from Settlement; Reduction of Foundation Strength; Cracking and Differential Settlement due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program

Cracking due to settlement is not an aging effect requiring management for concrete components below grade because the total differential settlement experienced in the past 20 years is well within the permissible limits for these types of structures and no settlement has manifested itself via cracked walls or cracked foundations. Foundations of all Columbia plant structures are supported on structural backfill. The backfill provides safe bearing for the structural foundations, and settlements are estimated to be minimal. In order to compare the calculated to actual settlement, measurement points were established at the corners of the substructure of the Reactor Building, Radwaste Control Building, Spray Ponds, and along the four sides of the sub-structure of the Turbine Generator Building. These points have been monitored systematically since the beginning of construction. The settlement observation records to date for these facilities are included in the FSAR, Appendix 2.5H. The results of settlement monitoring program show that the actual maximum differential settlements are well within the estimated differential settlements and that they remain of no consequence to the design of plant structures appurtenances. The measured settlement rate in the time frame from 1986 to 1991 has virtually leveled off (i.e., zero settlement) for the Reactor, Radwaste Control, and Turbine Generator buildings and was less than an average of 0.001 feet per year for both Spray Ponds. Therefore, commitments regarding settlement have been satisfied as any future settlements during the lifetime of the plant will not adversely affect the plant structures or appurtenances.

Columbia does not employ a de-watering system in any of the site structures for control of settlement since the groundwater level at the site is sufficiently lower than the deepest foundation in the complex. The Primary Containment base foundation is not constructed of porous concrete below-grade and is not subject to flowing water.

Therefore, cracks and distortion due to increased stress levels from settlement, and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete are not applicable to the Primary Containment concrete subfoundations.

3.5.2.2.1.3 Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

ASME Code, Section III, Division 2, Subsection CC indicates that aging due to elevated temperature exposure is not significant as long as concrete general area temperatures do not exceed 150 °F and local area temperatures do not exceed 200 °F. During normal operation, areas within Primary Containment are within these temperature limits. Normal temperature limits are given in FSAR Table 3.11-1. The temperature for the Primary Containment is maintained below 150 °F during normal operation, 135 °F bulk average maximum. The area beneath the RPV is a localized area with a maximum temperature limit of 165 °F, which is below the 200 °F threshold for localized areas.

Piping contained in the Primary Containment is not in direct contact with concrete and the concrete temperature surrounding hot penetrations, such as the main steam line penetrations, is maintained at less than or equal to 200 °F. Columbia specifications contain required insulation thicknesses for high temperature process piping. Consequently, localized hot spots on concrete are not expected from exposure to adjacent piping.

Therefore, reduction of strength and modulus of concrete due to elevated temperatures are not aging effects requiring management for the Primary Containment concrete components.

3.5.2.2.1.4 Loss of Material due to General, Pitting, and Crevice Corrosion

Loss of material due to corrosion in steel elements of accessible areas is managed by the Inservice Inspection (ISI) Program – IWE and the Appendix J Program. In addition to the Inservice Inspection (ISI) Program – IWE and the Appendix J Program, loss of material due to pitting and crevice corrosion for steel elements exposed to treated water (i.e., suppression chamber) is managed by the BWR Water Chemistry Program.

Loss of material due to corrosion in steel elements of inaccessible areas is not significant based on the following information.

The GE BWR Mark II steel Primary Containment is located within the Reactor Building and is protected from weather. The Primary Containment consists of an upper drywell and a lower suppression pool. The Primary Containment does not have boron reactivity control. The drywell and suppression pool atmosphere is inerted with nitrogen during normal operation. These are all positive influences for limiting loss of material due to corrosion in accessible and inaccessible areas.

The drywell floor peripheral seal is made of stainless steel and is welded to the primary containment vessel and to the underside of the circular closure girder embedded in the drywell floor. There are no concrete to metal moisture barriers at the drywell floor.

A sand filled pocket area is provided at the surrounding exterior of the primary containment vessel near the base. The sand filled pocket area is used to collect any drainage between the primary containment vessel exterior and the biological shield wall. An embedded steel closure ring is installed on the top of the sand filled transition area. Due to the possibility of containment shell degradation from corrosion induced by a moist environment in the sand pocket region, Columbia has committed to monitor humidity levels in this region. Columbia has implemented a procedure to survey the relative humidity of air drawn from within the containment annulus sand pocket region. [Reference NRC Accession Number ML042530061]

As a result of the design features and the committed surveillance indicated above, significant corrosion of inaccessible areas of the Primary Containment is not expected.

The continued monitoring of the drywell for loss material due to general, pitting, and crevice corrosion through the Inservice Inspection (ISI) Program – IWE and Appendix J Program provides reasonable assurance that loss of material in inaccessible areas of the drywell is insignificant and will be detected prior to the loss of an intended function.

3.5.2.2.1.5 Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

The Primary Containment is a GE BWR Mark II steel containment design. There are no prestressed tendons associated with the Primary Containment design.

As a result of the Primary Containment design, loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature is not an aging effect applicable to the Primary Containment.

3.5.2.2.1.6 Cumulative Fatigue Damage

This NUREG-1800 discussion involves metal fatigue of steel elements, such as containment penetration sleeves and bellows, vent lines, vent line bellows, vent header, and downcomers. The containment design includes penetrations, hatches, drywell head, downcomer vents, safety relief valve (SRV) discharge piping, and SRV quenchers. Containment process line penetrations are of welded steel construction without expansion bellows, gaskets, or sealing compounds and are an integral part of the construction.

Time-limited aging analyses are evaluated in accordance with 10 CFR 54.21(c) as documented in Section 4. Fatigue time-limited aging analyses are evaluated as documented in Section 4.6.

3.5.2.2.1.7 Cracking due to Stress Corrosion Cracking (SCC)

Stress corrosion cracking (SCC) requires a combination of a corrosive environment, susceptible materials, and high tensile stresses.

The primary containment penetrations are of welded steel construction without expansion bellows, gaskets, or sealing compounds and are an integral part of the construction. The penetration sleeves, vent headers, and downcomers are fabricated from carbon steel.

(1) SCC is not an applicable aging effect for the primary containment penetration sleeves, vent line headers, or downcomers because they are carbon steel components not susceptible to SCC.

(2) To be susceptible to SCC, stainless steel must be subject to both high temperature (>140 °F) and an aggressive chemical environment. SCC is not an applicable aging effect for dissimilar metal welds in the primary containment penetration sleeves since the welds are located inside the primary containment drywell or outside the drywell (within the Reactor Building), and are not subject to an aggressive chemical environment.

The Primary Containment is designed to permit appropriate periodic inspection of all penetrations. The design includes provisions for periodic testing at containment design pressure of the leaktightness of pressure containing or leakage limiting boundaries such as air locks, door seals, penetrations, drywell head, and access hatches.

A review of Columbia operating experience indicates that cracking due to SCC has not been a concern for the steel containment pressure boundary. As a result, cracking due to SCC is not applicable for the Primary Containment pressure boundary.

For the steel elements of containment that are part of the IWE pressure boundary; both the Inservice Inspection (ISI) Program - IWE and the Appendix J Program are used to monitor for degradation.

3.5.2.2.1.8 Cracking due to Cyclic Loading

Columbia penetrations do not use expansion bellows, and penetration sleeves are fabricated of carbon steel.

Cracking of metal components as a result of cyclic loads is a potential aging effect. However, review of the Columbia containment and associated operating experience concluded that cyclic loading from plant heatups and cooldowns, containment testing, and system vibration was very low or limited in numbers of cycles; and, therefore, additional methods of detecting postulated cracking are not warranted. Note that the cyclic loading of steel elements has been analyzed as a time-limited aging analysis; refer to Section 3.5.2.2.1.6 above.

For the steel elements of containment that are part of the IWE pressure boundary; both the Inservice Inspection (ISI) Program - IWE and the Appendix J Program are used to monitor for degradation. A review of Columbia operating experience indicates that cracking due to cyclic loading has not been a concern for steel containment pressure boundary components.

3.5.2.2.1.9 Loss of Material (Scaling, Cracking, and Spalling) due to Freeze-Thaw

The Primary Containment is a GE BWR Mark II steel containment design located within the Reactor Building. Loss of material (scaling, cracking, and spalling) due to freeze-thaw is applicable only to concrete containments exposed to weather.

Therefore, loss of material (scaling, cracking, and spalling) due to freeze-thaw is not an aging effect applicable to the Primary Containment.

3.5.2.2.1.10 Cracking due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability due to Leaching of Calcium Hydroxide

Primary Containment concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

Columbia requires that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with the Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or the Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289). Columbia specifications for concrete prohibit the use of calcium chloride in the concrete mix design.

Leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water. Seismic Category I structures and safety-related systems and components at Columbia are located above the present groundwater elevation 380 feet msl (mean sea level) and are not subject to any force effects of buoyancy and static water from this groundwater elevation. The bottom of the Reactor Building foundation mat is at elevation 400 feet 9 inches; therefore, foundation interaction with groundwater is unlikely. The Primary Containment concrete is not exposed to flowing water and the design and construction of the Primary Containment concrete is in accordance with accepted ACI Standards, thereby precluding expansion and reaction with aggregate and leaching of calcium hydroxide aging mechanisms.

Therefore, cracking due to expansion and reaction with aggregate, and increase in porosity and permeability due to leaching of calcium hydroxide are not aging effects requiring management for primary concrete components.

The absence of concrete aging effects is confirmed under the Structures Monitoring Program.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

3.5.2.2.2.1 Aging of Structures Not Covered by Structures Monitoring Program

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. NRC Interim Staff Guidance (ISG)-3 for aging management of concrete elements determined that concrete structures and components that are in the scope of license renewal are subject to visual inspection for the period of extended operation. Accordingly, Columbia complies with the staff guidance and concrete structures and components that are in the scope of license renewal include an aging management program to provide confirmation of the absence of aging effects requiring management. Columbia concurs with Interim Staff Guidance ISG-3 that sound engineering practices during material (concrete mix) design and construction together with sound inspection programs, in which the performance and condition of plant structures are periodically evaluated and monitored, are both necessary to maintain the serviceability of concrete nuclear structures. Additional discussion of specific aging effects and mechanisms follows.

(1) Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, 9 structures

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

The below-grade environment is non-aggressive (Chlorides < 500 ppm, Sulfates < 1,500 ppm, and pH > 5.5) and has been confirmed by water chemistry analysis results. Sampling results indicated groundwater pH minimum value of 6.9, chloride content maximum value of 36 ppm, and sulfate content maximum value of 323 ppm.

Annual rain water data summary from the National Atmospheric Deposition Program/National Trends Network (sample well located in Columbia River Gorge Skamania County) indicates the pH of precipitation sampled was 5.4, which is mildly acidic. Concrete components exposed to air-outdoor has proper drainage and slope design that limits the duration that concrete is exposed to mildly acidic rain water. The external surfaces are not continuously wetted (annual precipitation only amounts to less than 7 inches) or exposed to an aggressive ambient environment (such as a saltwater atmosphere, sulfur dioxide, etc.) or industrial locations. Rain water results in exposure for only intermittent periods of time; therefore, its mildly acidic aggressiveness is non-significant.

The concrete components below grade are not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding embedded steel corrosion aging mechanism.

Therefore, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not aging effects requiring management for the concrete structure components.

(2) Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1-5, 7, 9 structures

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

The below-grade environment is non-aggressive (Chlorides < 500 ppm, Sulfates < 1,500 ppm, and pH > 5.5) and has been confirmed by water chemistry analysis results. Sampling results indicated groundwater pH minimum value of 6.9, chloride content maximum value of 36 ppm, and sulfate content maximum value of 323 ppm.

Annual rain water data summary from the National Atmospheric Deposition Program/National Trends Network (sample well located in Columbia River Gorge Skamania County) indicates the pH of precipitation sampled was 5.4, which is mildly acidic. Concrete components exposed to air-outdoor has proper drainage and slope design that limits the duration that concrete is exposed to mildly acidic rain water. The external surfaces are not continuously wetted (annual precipitation only amounts to less than 7 inches) or exposed to an aggressive ambient environment (such as a saltwater atmosphere, sulfur dioxide, etc.) or industrial locations. Rain water results in exposure for only intermittent periods of time; therefore, its mildly acidic aggressiveness is non-significant.

The concrete components below grade are not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards thereby precluding aggressive chemical attack aging mechanism.

There are also aggressive chemicals stored at the plant and system leakage that could cause structural components to be exposed to chemicals is possible. However, accidental chemical spills are negligible since spills are cleaned up quickly in accordance with plant housekeeping procedures. System leakages are event driven and are not expected to continue for the extensive periods required for concrete degradation, and repairs would be made prior to loss of intended function.

Therefore, increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack are not aging effects requiring management for concrete structure components below grade.

However, the Structures Monitoring Program will include review of site groundwater and raw water pH, chlorides, and sulfates in order to validate that the below-grade environment remains non-aggressive during the period of extended operation.

(3) Loss of material due to corrosion for Groups 1-5, 7, 8 structures

The Structures Monitoring Program is credited for aging management of loss of material due to corrosion for Columbia Groups 1-5, 7 and 8 structures. Tanks subject to AMR are evaluated with the respective mechanical systems. Tank anchorages are managed by the Structures Monitoring Program.

(4) Loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, 7-9 structures

Columbia is located in an area where weathering conditions are moderate (weathering index 100 to 500 day-inch per year). The structures are designed with proper drainage and slope such that ponding or prolonged exposure to standing water on concrete surfaces is not significant.

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete, which results in good freeze-thaw and sulfate resistance.)

The design and construction of the concrete is in accordance with accepted ACI Standards that preclude freeze-thaw aging mechanism.

Therefore, loss of material (spalling, scaling) and cracking due to freeze-thaw are not aging effects requiring management for concrete structure components.

(Note that loss of material (spalling, scaling) and cracking due to freeze-thaw are aging effects requiring management for Columbia water control structures (Group 6 structures) exposed to raw water because the concrete located in water control structures may become saturated and therefore could be susceptible to freeze-thaw. Freeze-thaw on water control structures typically manifest near the water line; concrete component submerged in raw water (e.g., spray pond foundation) is not susceptible to freeze-thaw. Columbia plant operating experience has confirmed freeze-thaw degradation on concrete exposed to raw water.)

(5) Cracking due to expansion and reaction with aggregates for Groups 1-5, 7-9 structures

Columbia design specifications require that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with ASTM Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289).

The design and construction of the concrete is in accordance with accepted ACI Standards that preclude the expansion and reaction with aggregate aging mechanism.

Therefore, cracking due to expansion and reaction with aggregates is not an aging effect requiring management for concrete structure components.

(6) Cracks and distortion due to increased stress levels from settlement for Groups 1-3, 5-9 structures

Cracking due to settlement is not an aging effect requiring management for concrete components below grade because the total differential settlement experienced in the past 20 years is well within the permissible limits for these types of structures and no settlement has manifested itself via cracked walls or cracked foundations. Foundations of all Columbia plant structures are supported on structural backfill. The backfill provides safe bearing for the structural foundations, and settlements are estimated to be minimal. In order to compare the calculated to actual settlement, measurement points were established at the corners of the substructure of the Reactor Building, Radwaste Control Building, Spray Ponds, and along the four sides of the sub-structure of the Turbine Generator Building. These points have been monitored systematically since the beginning of construction. The settlement observation records to date for these facilities are included in the FSAR, Appendix 2.5H. The results of settlement monitoring program show that the actual maximum differential settlements are well within the estimated differential settlements and that they remain of no consequence to the design of plant structures appurtenances. The measured settlement rate in the time frame from 1986 to 1991 has virtually leveled off (i.e., zero settlement) for the Reactor, Radwaste Control, and Turbine Generator buildings and was less than an average of 0.001 feet per year for both Spray Ponds. Therefore, commitments regarding settlement have been satisfied as any future settlements during the lifetime of the plant will not adversely affect the plant structures or appurtenances.

Columbia does not employ a de-watering system in any of the site structures for control of settlement since the groundwater level at the site is sufficiently lower than the deepest foundation in the complex.

Therefore, cracks and distortion due to increased stress levels from settlement are not aging effects requiring management for the concrete structural components.

(7) Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation for Groups 1-3, 5-9 structures

The concrete foundations are not constructed with porous concrete and are not subject to flowing water. Columbia does not employ a de-watering system at any of the site structures for control of settlement.

Therefore, reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations are not aging effects requiring management for the concrete foundations.

(8) Lock up due to wear could occur for Lubrite radial beam seats in BWR drywell, Reactor Pressure Vessel support shoes for PWR with nozzle supports, steam generator supports, and other sliding support bearings and sliding support surfaces

Lubrite plates are provided in certain situations to reduce friction on sliding support assemblies in Columbia in-scope structural components. They are used in association with such components as the radial beam seat connections on the vessel shell high temperature piping supports. Lubrite® is the trade name for a low friction lubricant material used in applications where relative motion (sliding) is desired. The Lubrite proprietary lubricant is a custom compound mixture of metals, metal oxides, minerals, and other lubricating materials combined with a lubricating binder. Lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. Additionally, Lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed. There are no known aging effects that would lead to a loss of intended function. Review of plant-specific operating experience identified no occurrences of Lubrite degradations. Therefore, there are no aging effects requiring management for Lubrite plates.

However, aging degradations of supports designed with or without sliding connections are managed by the Inservice Inspection (ISI) Program – IWF and the Structures Monitoring Program.

3.5.2.2.2.2 Aging Management of Inaccessible Areas

3.5.2.2.2.2.1 Below-Grade Inaccessible Concrete Areas – Freeze-Thaw

Columbia is located in an area where weathering conditions are moderate (weathering index 100 to 500 day-inch per year). The structures are designed with proper drainage and slope such that ponding or prolonged exposure to standing water on concrete surfaces is not significant.

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete, which results in good freeze-thaw and sulfate resistance.)

The design and construction of the concrete is in accordance with accepted ACI Standards that preclude freeze-thaw aging mechanism.

Therefore, loss of material (spalling, scaling) and cracking due to freeze-thaw are not aging effects requiring management for the below-grade inaccessible concrete components.

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.2.2 Below-Grade Inaccessible Concrete Areas – Expansion and Reaction with Aggregates

Columbia design specifications require that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with ASTM Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289).

The design and construction of the concrete is in accordance with accepted ACI Standards thereby precluding the expansion and reaction with aggregate aging mechanism.

Therefore, cracking due to expansion and reaction with aggregates is not an aging effect requiring management for the below-grade inaccessible concrete components.

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.2.3 Below-Grade Inaccessible Concrete Areas – Settlement and Erosion

Cracking due to settlement is not an aging effect requiring management for concrete components below grade because the total differential settlement experienced in the past 20 years is well within the permissible limits for these types of structures and no settlement has manifested itself via cracked walls or cracked foundations. Foundations of all Columbia plant structures are supported on structural backfill. The backfill provides safe bearing for the structural foundations, and settlements are estimated to be minimal. In order to compare the calculated to actual settlement, measurement points were established at the corners of the substructure of the Reactor Building, Radwaste Control Building, Spray Ponds, and along the four sides of the sub-structure of the Turbine Generator Building. These points have been monitored systematically since the beginning of construction. The settlement observation records to date for these facilities are included in the FSAR, Appendix 2.5H. The results of the settlement monitoring program show that the actual maximum differential settlements are well within the estimated differential settlements and that they remain of no consequence to the design of plant structures appurtenances. The measured settlement rate in the time frame from 1986 to 1991 has virtually leveled off (i.e., zero settlement) for the Reactor, Radwaste Control, and Turbine Generator buildings and was less than an average of 0.001 feet per year for both Spray Ponds. Therefore, commitments regarding settlement have been satisfied as any future settlements during the lifetime of the plant will not adversely affect the plant structures or appurtenances.

Columbia does not employ a de-watering system in any of the site structures for control of settlement since the groundwater level at the site is sufficiently lower than the deepest foundation in the complex.

Therefore, cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations are not aging effects requiring management for the below-grade inaccessible concrete components.

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.2.4 Below-Grade Inaccessible Concrete Areas – Aggressive Chemical Attack and Corrosion of Embedded Steel

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specifications yields concrete with a low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

The below-grade environment is non-aggressive (Chlorides < 500 ppm, Sulfates < 1,500 ppm, and pH > 5.5) and has been confirmed by water chemistry analysis results. Sampling results indicate a groundwater pH minimum value of 6.9, chloride content maximum value of 36 ppm, and sulfate content maximum value of 323 ppm.

The concrete components below grade are not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding the aggressive chemical attack and embedded steel corrosion aging mechanisms.

Therefore, increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not aging effects requiring management for the below-grade inaccessible concrete components.

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will include review of site groundwater and raw water pH, chlorides, and sulfates in order to validate that the below-grade environment remains non-aggressive during the period of extended operation and will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.2.5 Below-Grade Inaccessible Concrete Areas – Leaching of Calcium Hydroxide

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specifications yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

Leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water.

The concrete components below grade are not exposed to flowing water and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding the leaching of calcium hydroxide aging mechanism. Groundwater hydraulic pressure is not a concern at Columbia. Seismic Category I structures and safety-related systems and components are located above the present groundwater elevation 380 feet msl (mean sea level) and are not subject to any force effects of buoyancy and static water from this groundwater elevation. The lowest structure foundation mat, for the Reactor Building, is at elevation 400 feet 9 inches, which is approximately 20 feet above the groundwater table elevation.

Therefore, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide are not aging effects requiring management for the below-grade inaccessible concrete components.

3.5.2.2.2.3 Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

Columbia in-scope concrete structures and concrete components are not exposed to temperature limits associated with aging degradation due to elevated temperature. The general air temperatures in safety-related and other structures are maintained below the 150 °F threshold for these aging effects to be applicable. Normal temperature limits are given in FSAR Table 3.11-1. The area beneath the Reactor Pressure Vessel is a localized area and has a maximum temperature limit of 165 °F, which is below the 200 °F threshold for localized areas.

Piping contained in these structures is not in direct contact with concrete and the concrete temperature surrounding hot penetrations such as the main steam line penetrations in the main steam tunnel is maintained at less than or equal to 200 °F. Columbia specifications contain required insulation thicknesses for high temperature process piping. Consequently, localized hot spots on concrete are not expected from exposure to adjacent piping.

Therefore, reduction of strength and modulus of concrete due to elevated temperatures are not aging effects requiring management for the concrete components.

3.5.2.2.2.4 Aging Management of Inaccessible Areas for Group 6 Structures

3.5.2.2.2.4.1 Below-Grade Inaccessible Concrete Areas – Aggressive Chemical Attack and Corrosion of Embedded Steel

The Structures Monitoring Program – Water Control Structures Inspection is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. Corrosion of structural steel components is addressed by the Structures Monitoring Program. Additional discussion of specific aging effects follows.

The ultimate heat sink consists of two Spray Ponds and two Standby Service Water Pump Houses. The water control structures are the Spray Ponds, Standby Service Water Pump Houses, Circulating Water Pump House (including circulating water basin), Makeup Water Pump House, and the cooling tower basins.

The below-grade environment is non-aggressive (Chlorides < 500 ppm, Sulfates < 1,500 ppm, and pH > 5.5) and has been confirmed by water chemistry analysis results. Sampling results indicate a groundwater pH minimum value of 6.9, chloride content maximum value of 36 ppm, and sulfate content maximum value of 323 ppm. Raw water sampling results indicate a raw water pH minimum value of 6.6, chloride content maximum value of 60 ppm, and sulfate content maximum value of 127 ppm.

Columbia concrete is designed in accordance with ACI 318-63 or 318-71 and constructed in accordance with ACI 301-66 or 301-72 using ingredients conforming to ACI and ASTM standards. Concrete constructed to these criteria has a low water-to-cement ratio of less than 0.50 and an air entrainment between 3 and 6 percent and provides a good quality dense concrete with a low permeability, which meets the intent of ACI 201.2R-77. (Note: Columbia does not specify water-to-cement ratio, however for massive concrete (sections more than 30 inches in the least dimension) a minimum slump of 1 inch and a maximum slump of 3 inches is provided so that the average for all batches or of the most recent 10 batches tested, whichever is lower, does not exceed 2-1/2 inches. Water-to-cement ratio is established by tests of trial mixes using the materials and slump proposed for use. The slump working limit at point of placement specified in design specification yields concrete with low water-to-cement ratio since the average slump at the point of placement is less than the working limit, which is the maximum slump for estimating the quantity of mixing water to be used in the concrete.)

The water control structure's concrete is not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding the aggressive chemical attack and embedded steel corrosion aging mechanisms.

Therefore, increase in porosity and permeability, cracking, loss of material (spalling, scaling)/aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling)/corrosion of embedded steel are not aging effects requiring management for the water control structure's concrete.

The absence of concrete aging effects is confirmed under the Structures Monitoring Program.

3.5.2.2.2.4.2 Below-Grade Inaccessible Concrete Areas – Freeze-Thaw

Loss of material (spalling, scaling) and cracking due to freeze-thaw are aging effects requiring management for concrete components exposed to raw water because the concrete located in water control structures may become saturated and therefore could be susceptible to freeze-thaw. Concrete components submerged in raw water (e.g., spray pond foundation) are not susceptible to freeze-thaw. The Structures Monitoring Program – Water Control Structures Inspection is credited for monitoring degradation of the Spray Ponds, Standby Service Water Pump Houses, Circulating Water Pump House (including circulating water basin), Makeup Water Pump House, and the cooling tower basins. The Structures Monitoring Program will be enhanced to include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.4.3 Below-Grade Inaccessible Concrete Areas – Expansion and Reaction with Aggregate and Leaching of Calcium Hydroxide

Columbia design specifications require that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with ASTM Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289).

Leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water.

The water control structures are exposed to flowing water, however the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding the expansion and reaction with aggregate and leaching of calcium hydroxide aging mechanisms. Groundwater hydraulic pressure is not a concern at Columbia. Seismic Category I structures and safety-related systems and components are located above the present groundwater elevation 380 feet msl (mean sea level) and are not subject to any force effects of buoyancy and static water from this groundwater elevation. The foundation slab at the bottom of the Standby Service Water Pump House pump chambers where it intersects the spray pond foundation is at elevation 404 feet 9 inches, which is approximately 24 feet above the groundwater table elevation.

Therefore, cracking due to expansion and reaction with aggregate, and increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide are not aging effects requiring management for the below-grade concrete structures.

The Structures Monitoring Program – Water Control Structures Inspection is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will be enhanced to include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation.

3.5.2.2.2.5 Cracking due to Stress Corrosion Cracking and Loss of Material due to Pitting and Crevice Corrosion

No tanks with stainless steel liners are included in the structural reviews for aging management. Tanks subject to AMR are evaluated with the respective mechanical systems.

3.5.2.2.2.6 Aging of Supports Not Covered by Structures Monitoring Program

(1) Loss of material due to general and pitting corrosion for Groups B2-B5 supports

Loss of material due to general and pitting corrosion for Groups B2-B5 supports is managed by the Structures Monitoring Program.

(2) Reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports

Cracking due to service-induced vibration or fatigue that causes a reduction in concrete anchor capacity is not an aging effect requiring management because Columbia concrete support components are not subject to significant cyclic loading. Reinforced concrete components are designed by the strength method per ACI 318 and structural steel components are designed by the working stress method per American Institute of Steel Construction (AISC) specification, resulting in good, low cycle fatigue properties. Failures from high cycle fatigue due to equipment vibration loads are detected early in plant life and actions would be taken to prevent reoccurrence. At Columbia, connections for supports of running machinery or other high vibration environmental applications are designed as a slip-critical connection. Vibratory and rotating equipment are supported by cast-in-place, through bolted, or grouted-in anchors. Therefore, cracking due to fatigue at locations of cast-in-place, through bolted, or grouted-in anchors is not an aging effect requiring management.

The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structures and structural components, in accordance with the NRC position on managing concrete, even if the AMR did not identify aging effects requiring management.

(3) Reduction or loss of isolation function due to degradation of vibration isolation elements for Group B4 supports

Vibration isolation elements are not used on Columbia's vibratory and rotating equipment such as pumps, compressors, or air handling units. However, vibration isolators are used on certain control panels within skid mounted complex assemblies such as the diesel engine. These components are treated as sub component (e.g., panels, pipe supports, heat exchanger supports, engine anchorages, instrumentation supports on the diesel engine skid) to the host component and are managed as part of the host component during Structures Monitoring Program inspections. Degradation of vibration isolation elements for Group B4 supports is managed by the Structures Monitoring Program.

3.5.2.2.2.7 Cumulative Fatigue Damage Due to Cyclic Loading

Time-limited aging analyses are evaluated in accordance with 10 CFR 54.21(c) as documented in Section 4. During the process of identifying time-limited aging analyses in the current licensing basis, no fatigue analyses were identified for component support members, anchor bolts, or welds for Groups B1.1, B1.2, and B1.3.

3.5.2.2.3 Quality Assurance for Aging Management of Non-safety Related Components

Quality Assurance provisions applicable to license renewal are discussed in Appendix B, Section B.1.3.

3.5.2.3 Time-Limited Aging Analyses

The time-limited aging analyses identified below are associated with the Containments, Structures, and Component Supports commodities. The section of the application that contains the time-limited aging analysis review results is indicated in parentheses.

- Metal Fatigue (Section 4.6, Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses)

3.5.3 Conclusions

The Containments, Structures, and Component Supports subject to AMR have been identified in accordance with the criteria of 10 CFR 54.21. The aging management programs selected to manage the effects of aging on structural components and commodities are identified in the following tables and Section 3.5.2.1. A description of the aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the Containments, Structures, and Component Supports will be managed such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
PWR Concrete (Reinforced and Prestressed) and Steel Containments BWR Concrete and Steel (Mark I, II, and III) Containments					
3.5.1-01	Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes, plant-specific, if the environment is aggressive	The Primary Containment concrete is not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding aggressive chemical attack and embedded steel corrosion aging mechanisms. Refer to Section 3.5.2.2.1.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-02	Concrete elements; All	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if not within the scope of the applicant's structures monitoring program or a de-watering system is relied upon	Not applicable for Columbia. Columbia does not employ a de-watering system in any of the site structures for control of settlement. The total differential settlement experienced in the past 20 years is well within the permissible limits for these types of structures and no settlement has manifested itself via cracked walls or cracked foundations, therefore, this aging mechanism is not applicable. Refer to Section 3.5.2.2.1.2 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	*Further Evaluation Recommended*	Discussion
3.5.1-03	Concrete elements: foundation, sub-foundation	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program If a de-watering system is relied upon for control of erosion of cement from porous concrete subfoundations, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if not within the scope of the applicant's structures monitoring program or a de-watering system is relied upon	The Primary Containment base foundation slabs are not constructed of porous concrete below-grade and are not subject to flowing water, thereby precluding these aging effects and mechanisms. Columbia does not employ a de-watering system at any of the site structures for control of settlement or erosion of cement from concrete subfoundations. Refer to Section 3.5.2.2.1.2 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-04	Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific aging management program is to be evaluated	Yes, plant-specific if temperature limits are exceeded	The temperature for the Primary Containment is maintained below 150 °F during normal operation, 135 °F bulk average maximum. The area beneath the RPV is a localized area and has a maximum temperature limit of 165 °F which is below the 200 °F threshold for localized area. Piping contained in the Primary Containment is not in direct contact with concrete and the concrete temperature surrounding hot penetrations such as the main steam line penetrations is maintained at less than or equal to 200 °F. These are below the threshold temperatures for these aging effects to be applicable. Refer to Section 3.5.2.2.1.3 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-05	Steel elements: Drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor, suppression chamber (as applicable)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE), and10 CFR Part 50, Appendix J.	Yes, if corrosion is significant for inaccessible areas	Consistent with NUREG-1801. Loss of material due to corrosion in steel elements is managed by the Inservice Inspection (ISI) Program – IWE and the Appendix J Program. In addition, loss of material due to pitting and crevice corrosion for steel elements exposed to treated water (i.e., suppression chamber) is managed by the BWR Water Chemistry Program. Refer to Section 3.5.2.2.1.4 for further information.
3.5.1-06	Steel elements: steel liner, liner anchors, integral attachments	Loss of material due to general, pitting and crevice corrosion	ISI (IWE), and 10 CFR Part 50, Appendix J.	Yes, if corrosion is significant for inaccessible areas	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design. This table item pertains to PWR steel containments and BWR Mark III concrete containments.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-07	Prestressed containment tendons	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design. There are no prestressed tendons associated with the Primary Containment design. Refer to Section 3.5.2.2.1.5 for further information.
3.5.1-08	Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	TLAAs are evaluated in accordance with 10 CFR 54.21(c) as documented in Section 4. Fatigue TLAAs are evaluated as documented in Section 4.6. Refer to Section 3.5.2.2.1.6 for further information.
3.5.1-09	Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	TLAAs are evaluated in accordance with 10 CFR 54.21(c) as documented in Section 4. Fatigue TLAAs are evaluated as documented in Section 4.6. Refer to Section 3.5.2.2.1.6 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-10	Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examinations/evaluations for bellows assemblies and dissimilar metal welds.	Yes, detection of aging effects is to be evaluated	Not applicable for Columbia. The primary containment penetrations are of welded steel construction without expansion bellows, gaskets, or sealing compounds and are an integral part of the construction. The penetration sleeves, vent headers and downcomers are fabricated from carbon steel. A review of Columbia operating experience indicates that cracking due to SCC has not been a concern for steel containment pressure boundary. Cracking due to SCC is not applicable for the primary containment pressure boundaries. Refer to Section 3.5.2.2.1.7 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-11	Stainless steel vent line bellows	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examination/evaluation for bellows assemblies and dissimilar metal welds.	Yes, detection of aging effects is to be evaluated	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design. There are no stainless steel vent line bellows associated with the Primary Containment design. Refer to Section 3.5.2.2.1.7 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-12	Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes, detection of aging effects is to be evaluated	Not applicable for Columbia. Columbia penetrations do not use expansion bellows and penetration sleeves are fabricated of carbon steel. The AMR, as supported by operating experience, concluded that cyclic loading from plant heatups and cooldowns, containment testing, and from system vibration was very low or limited in numbers of cycles; therefore, additional methods of detecting postulated cracking are not warranted. This aging effect and mechanism is not applicable. Refer to Section 3.5.2.2.1.8 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-13	Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes, detection of aging effects is to be evaluated	Not applicable for Columbia. The AMR, as supported by operating experience, concluded that cyclic loading from plant heatups and cooldowns, containment testing, and from system vibration was very low or limited in numbers of cycles; therefore, additional methods of detecting postulated cracking are not warranted. This aging effect and mechanism is not applicable. Refer to Section 3.5.2.2.1.8 for further information.
3.5.1-14	Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable)	Loss of material (Scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Yes, for inaccessible areas of plants located in moderate to severe weathering conditions	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design located within the Reactor Building. This aging effect and mechanism is not applicable. Refer to Section 3.5.2.2.1.9 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-15	Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes, if concrete was not constructed as stated for inaccessible areas	The design and construction of the Columbia concrete is in accordance with accepted ACI Standards. Cracking due to expansion and reaction with aggregate, and increase in porosity and permeability due to leaching of calcium hydroxide are not aging effects requiring management for the Primary Containment concrete components. The absence of concrete aging effects is confirmed under the Structures Monitoring Program. Refer to Section 3.5.2.2.1.10 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-16	Seals, gaskets, and moisture barriers	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Consistent with NUREG-1801. The subject aging effects are a result of cracking and change in material properties. Seals and gaskets for personnel airlock, equipment hatch and CRD hatch are evaluated with the host component. See Item Number 3.5.1-17. The Inservice Inspection (ISI) Program - IWE and the Appendix J Program are used to manage the aging effects of cracking and change in material properties which result in loss of sealing and leakage through containment. The drywell floor peripheral seal is made of stainless steel and is welded to the primary containment vessel and to the underside of the circular closure girder embedded in the drywell floor. There are no elastomeric moisture barrier seals in the drywell floor design.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-17	Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanisms	10 CFR Part 50, Appendix J and Plant Technical Specifications	No	Consistent with NUREG-1801. Locks, hinges and closure mechanisms are evaluated with the host component. The personnel airlock, equipment hatch and CRD removal hatch are managed by the Inservice Inspection (ISI) Program - IWE and the Appendix J Program. Plant Technical Specification ensures that access airlocks maintain leak tightness in the closed position.
3.5.1-18	Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch and CRD hatch	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J.	No	Consistent with NUREG-1801. The listed components are managed by the Inservice Inspection (ISI) Program - IWE and the Appendix J Program.
3.5.1-19	Steel elements: stainless steel suppression chamber shell (inner surface)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design. The suppression chamber is constructed of carbon steel.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-20	Steel elements: suppression chamber liner (interior surface)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable for Columbia. The Primary Containment is a GE BWR Mark II steel containment design. This table item pertains to BWR Mark I and BWR Mark II concrete containments.
3.5.1-21	Steel elements: drywell head and downcomer pipes	Fretting or lock up due to mechanical wear	ISI (IWE)	No	Columbia's plant operating experience has not identified fretting or lock up due to mechanical wear for the drywell head and downcomer pipes. The downcomer pipes are embedded in and supported by the reinforced concrete slab of the drywell floor.
3.5.1-22	Prestressed containment: tendons and anchorage components	Loss of material due to corrosion	ISI (IWL)	No	Not applicable for Columbia. Columbia is not a prestressed containment. There are no tendons associated with the Primary Containment design.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-23	All Groups except Group 6: interior and above grade exterior concrete	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Yes, if not within the scope of the applicant's structures monitoring program	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.1 for further information.
3.5.1-24	All Groups except Group 6: interior and above grade exterior concrete	Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring Program	Yes, if not within the scope of the applicant's structures monitoring program	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-25	All Groups except Group 6: steel components: all structural steel	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the structures monitoring program is to include provisions to address protective coating monitoring and maintenance.	Yes, if not within the scope of the applicant's structures monitoring program	Consistent with NUREG-1801. The Structures Monitoring Program is credited for aging management of this aging effect and mechanism. The effect of coating debris on ECCS pump suction strainers has been evaluated to have no safety impact on strainer operation (see FSAR Section 6.1.2). Containment coatings are subject to ongoing oversight that addresses their current status and will continue to address their status over the period of license renewal. Protective coatings are not relied upon to manage the effects of aging at Columbia. Refer to Section 3.5.2.2.2.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-26	All Groups except Group 6: accessible and inaccessible concrete: foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Yes, if not within the scope of the applicant's structures monitoring program Or for inaccessible areas of plants located in moderate to severe weathering conditions	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.1 for further information. Refer to Section 3.5.2.2.2.2.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-27	All Groups except Group 6: accessible and inaccessible interior/exterior concrete	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if not within the scope of the applicant's structures monitoring program Or concrete was not constructed as stated for inaccessible areas	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.1 for further information. The design and construction of the Columbia concrete is in accordance with accepted ACI Standards, thereby precluding the reaction with aggregates aging mechanism. Refer to Section 3.5.2.2.2.2.2 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-28	Groups 1-3, 5-9: All	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if not within the scope of the applicant's structures monitoring program Or a de-watering system is relied upon	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.1 for further information. Columbia does not employ a de-watering system at any of the site structures for control of settlement. Refer to Section 3.5.2.2.2.2.3 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-29	Groups 1-3, 5-9: foundation	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if not within the scope of the applicant's structures monitoring program Or a de-watering system is relied upon	Not applicable for Columbia. The concrete foundations at Columbia are not constructed with porous concrete and are not subject to flowing water. Refer to Section 3.5.2.2.2.1 for further information. Columbia does not employ a de-watering system at any of the site structures for control of settlement. Refer to Section 3.5.2.2.2.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-30	Group 4: Radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; Steam generator supports	Lock-up due to wear	ISI (IWF) or Structures monitoring Program	Yes, if not within the scope of ISI or structures monitoring program	Aging degradations of supports designed with or without sliding connections are managed by the Inservice Inspection (ISI) Program – IWF and the Structures Monitoring Program. The inspection criteria for supports within the programs effectively envelope misalignment and accumulation of debris. Lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed. There are no known aging effects that would lead to a loss of intended function. Refer to Section 3.5.2.2.2.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-31	Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation	Increase in porosity and permeability, cracking, loss of material (spalling, scaling)/ aggressive chemical attack; Cracking, loss of bond, and loss of material (spalling, scaling)/corrosion of embedded steel	Structures Monitoring Program; Examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes, plant-specific, if environment is aggressive	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. The Structures Monitoring Program will include review of site ground water and raw water pH, chlorides, and sulfates in order to validate that the below-grade environment remains non-aggressive during the period of extended operation and will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation. Refer to Section 3.5.2.2.2.2.4 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-32	Groups 1-3, 5, 7-9: exterior above and below grade reinforced concrete foundations	Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide	Structures monitoring Program for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if concrete was not constructed as stated for inaccessible areas	The design and construction of the Columbia concrete is in accordance with accepted ACI Standards, thereby precluding the leaching of calcium hydroxide aging mechanism. Columbia concrete is not exposed to flowing water or groundwater hydraulic pressure, therefore, these aging effects and mechanisms do not require management for the below-grade inaccessible concrete structural components. Refer to Section 3.5.2.2.2.2.5 for further information.
3.5.1-33	Groups 1-5: concrete	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific aging management program is to be evaluated.	Yes, plant-specific if temperature limits are exceeded	Columbia in-scope concrete structures and concrete components are not exposed to temperature limits associated with aging degradation due to elevated temperature. Refer to Section 3.5.2.2.2.3 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-34	Group 6: Concrete; all	Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack; cracking, loss of bond, loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes, plant-specific if environment is aggressive	The Columbia Group 6 structures concrete is not exposed to an aggressive environment and the design and construction of the concrete is in accordance with accepted ACI Standards, thereby precluding aggressive chemical attack and embedded steel corrosion aging mechanisms. The absence of concrete aging effects is confirmed under the Structures Monitoring Program – Water Control Structures Inspection. Columbia is not committed to Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection. Refer to Section 3.5.2.2.2.4.1 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-35	Group 6: exterior above and below grade concrete foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Yes, for inaccessible areas of plants located in moderate to severe weathering conditions	The Structures Monitoring Program – Water Control Structures Inspection is credited for aging management and includes the 10 elements evaluation for the NUREG-1801 XI.S7 aging management program. Columbia is not committed to Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection. Loss of material (spalling, scaling) and cracking due to freeze-thaw are aging effects requiring management for concrete components exposed to raw water because the concrete may become saturated and therefore could be susceptible to freeze-thaw. Refer to Section 3.5.2.2.2.4.2 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-36	Group 6: all accessible/ inaccessible reinforced concrete	Cracking due to expansion/ reaction with aggregates	Accessible areas: Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if concrete was not constructed as stated for inaccessible areas	The design and construction of the Columbia concrete is in accordance with accepted ACI Standards, thereby precluding the expansion and reaction with aggregate aging mechanism. The absence of concrete aging effects is confirmed under the Structures Monitoring Program – Water Control Structures Inspection. The Structures Monitoring Program includes the 10 elements evaluation for the NUREG-1801 XI.S7 aging management program. Columbia is not committed to Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection. Refer to Section 3.5.2.2.2.4.3 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-37	Group 6: exterior above and below grade reinforced concrete foundation interior slab	Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide	For accessible areas, inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes, if concrete was not constructed as stated for inaccessible areas	The design and construction of the Columbia concrete is in accordance with accepted ACI Standards, thereby precluding leaching of calcium hydroxide aging mechanisms. The absence of concrete aging effects is confirmed under the Structures Monitoring Program – Water Control Structures Inspection. The Structures Monitoring Program includes the 10 elements evaluation for the NUREG-1801 XI.S7 aging management program. *Columbia is not committed to* Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection. Refer to Section 3.5.2.2.2.4.3 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-38	Groups 7, 8: Tank liners	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	A plant-specific aging management program is to be evaluated	Yes, plant specific	No tanks with stainless steel liners are included in the structural AMRs. Tanks subject to AMR are evaluated with their respective mechanical systems. Refer to Section 3.5.2.2.2.5 for further information.
3.5.1-39	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Yes, if not within the scope of the applicant's structures monitoring program	Consistent with NUREG-1801. Loss of material due to general and pitting corrosion for Groups B2-B5 supports is managed by the Structures Monitoring Program. Refer to Section 3.5.2.2.2.6 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-40	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring Program	Yes, if not within the scope of the applicant's structures monitoring program	The Structures Monitoring Program is credited for aging management of these effects and mechanisms for the affected concrete structural components, in accordance with the current NRC position, even if the AMR did not identify aging effects requiring management. Refer to Section 3.5.2.2.2.6 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-41	Vibration isolation elements	Reduction or loss of isolation function/radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Yes, if not within the scope of the applicant's structures monitoring program	Degradation of vibration isolation elements for Group B4 supports is managed by the Structures Monitoring Program. Vibration isolation elements are not used on Columbia's vibratory and rotating equipment such as pumps, compressors, or air handling units. However, vibration isolators are used on certain control panels within skid mounted complex assemblies such as the diesel engine. These components are treated as sub component to the host component and are managed as part of the host component during Structures Monitoring Program inspections. Refer to Section 3.5.2.2.2.6 for further information.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-42	Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	No fatigue analyses were identified for component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3. *Refer to Section 3.5.2.2.2.7 for further information.*
3.5.1-43	Groups 1-3, 5, 6: all masonry block walls	*Cracking due to restraint shrinkage, creep, and aggressive environment*	Masonry Wall Program	No	Masonry block walls are managed by the Structures Monitoring Program – Masonry Wall Inspection. The Structures Monitoring Program includes the 10 elements evaluation for the NUREG-1801 XI.S5 aging management program. Masonry block walls with a fire barrier intended function are also managed by the Fire Protection Program. The Structures Monitoring Program encompasses and implements the Masonry Wall Inspection.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-44	Group 6 elastomer seals, gaskets, and moisture barriers	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring Program	No	Consistent with NUREG-1801. Elastomeric components for Groups 1-3, 5, 6 structures are managed by the Structures Monitoring Program. Seals with a fire barrier intended function are managed by the Fire Protection Program. See Item Number 3.3.1-61. Loss of sealing is not an aging effect, but rather a consequence of elastomer degradation. Loss of sealing may be caused by cracking or change in material properties aging effects for elastomeric material.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-45	Group 6: exterior above and below grade concrete foundation; interior slab	Loss of material due to abrasion, cavitation	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	No	Loss of material due to abrasion or cavitation is not an aging effect requiring management for concrete components exposed to raw water because the Spray Pond water does not contain abrasive material and flow velocity in water control structures is less than the cavitation threshold. The absence of concrete aging effects is confirmed under the Structures Monitoring Program – Water Control Structures Inspection . The Structures Monitoring Program includes the 10 elements evaluation for the NUREG-1801 XI.S7 aging management program. Columbia is not committed to Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-46	Group 5: Fuel pool liners	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	No	Consistent with NUREG-1801. Loss of material is managed by the BWR Water Chemistry Program, monitoring of spent fuel pool water level in accordance with Technical Specifications, and monitoring of leak chase channels. The leak chase channels are designed to permit free gravity drainage to the radioactive drain system, the flow of which is monitored via operator rounds under the CLB as stated in FSAR Section 9.1.2.2.2. Cracking due to SCC is not an aging effect requiring management because SCC occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment and temperature, which are not found in the spent fuel pool. The spent fuel pool water temperature is below the 140°F threshold during normal operation.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-47	Group 6: all metal structural members	Loss of material due to general (steel only), pitting and crevice corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	Metal structural components within Group 6 structures are managed by the Structures Monitoring Program – Water Control Structures Inspection. The Structures Monitoring Program includes the 10 elements evaluation for the NUREG-1801 XI.S7 aging management program. Columbia is not committed to Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection. ASME metal structural components associated with Group 6 structures are managed by the Inservice Inspection (ISI) Program – IWF.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-48	Group 6: earthen water control structures - dams, embankments, reservoirs, channels, canals, and ponds	Loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	Not applicable for Columbia. There are no earthen structures associated with the standby Service Water Pump House or the Spray Pond. Under the current licensing bases the Spray Pond includes a 6-inch sedimentation allowance for water inventory considerations. This allowance includes all forms of accumulation, such as dust, silt, or volcanic ash. The spray ponds are cleaned whenever the sedimentation reaches 3 inches, which ensures adequate water supply even in the event of a design basis ashfall.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-49	Support members; welds; bolted connections; support anchorage to building structure	Loss of material/ general, pitting, and crevice corrosion	Water Chemistry and ISI(IWF)	No	Consistent with NUREG-1801. The listed structural components exposed to treated water are managed by the Inservice Inspection (ISI) Program – IWF and the BWR Water Chemistry Program. Non ASME structural components exposed to treated water are managed by the Structures Monitoring Program.
3.5.1-50	Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	No	Consistent with NUREG-1801. The listed structural components are managed by the Structures Monitoring Program.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-51	Group B1.1: high strength low-alloy bolts	Cracking due to stress corrosion cracking; loss of material due to general corrosion	Bolting Integrity	No	Three parameters are required for stress corrosion cracking (SCC) to occur: (1) a corrosive environment, (2) a susceptible material, and (3) tensile stresses greater than or equal to the yield strength of the material. Corrosive environments containing sodium hydroxide, seawater, nitrate solutions, sulfuric acids, or aggressive groundwater (chlorides > 500 ppm, sulfates > 1,500 ppm) are not present at Columbia. The internal environment of in-scope structures does not contain aggressive chemicals or contaminants under normal operating conditions. Therefore, the environmental conditions necessary for SCC to occur do not exist. Review of plant-specific operating experience identified no occurrences of SCC on high strength structural bolting.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-52	Groups B2, and B4: sliding support bearings and sliding support surfaces	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Aging degradations of supports designed with or without sliding connections are managed by the Structures Monitoring Program. The inspection criteria for supports within the programs effectively envelope misalignment and accumulation of debris.
3.5.1-53	Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure	Loss of material due to general and pitting corrosion	ISI (IWF)	No	Consistent with NUREG-1801. The listed structural components are managed by the Inservice Inspection (ISI) Program – IWF.

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-54	Groups B1.1, B1.2, and B1.3: Constant and variable load spring hangers; guides; stops;	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	Loss of mechanical function due to the listed mechanisms is not an aging effect identified in the Structural Tools or at Columbia. Proper design prevents distortion, overload, and fatigue due to vibratory and cyclic thermal loads. However, aging degradations on Groups B1.1, B1.2, and B1.3 constant and variable load spring hangers; guides; stops are managed by the Inservice Inspection (ISI) Program – IWF. The inspection criteria for supports within the programs effectively envelope misalignment and accumulation of debris.
3.5.1-55	PWR Only				

Table 3.5.1 Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801					
Item Number	**Component/Commodity**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5.1-56	Groups B1.1, B1.2, and B1.3: Sliding surfaces	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	Aging degradations of Groups B1.1, B1.2, and B1.3 supports designed with or without sliding connections are managed by the Inservice Inspection (ISI) Program – IWF. The inspection criteria for supports within the programs effectively envelope misalignment and accumulation of debris.
3.5.1-57	Groups B1.1, B1.2, and B1.3: Vibration isolation elements	Reduction or loss of isolation function/radiation hardening, temperature, humidity, sustained vibratory loading	ISI (IWF)	No	Not applicable for Columbia. There were no Groups B1.1, B1.2, and B1.3 vibration isolation elements identified at Columbia.
3.5.1-58	Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air - indoor uncontrolled	None	None	NA - No AEM or AMP	Consistent with NUREG-1801.
3.5.1-59	Stainless steel support members; welds; bolted connections; support anchorage to building structure	None	None	NA - No AEM or AMP	Consistent with NUREG-1801.

Table 3.5.2-1 Aging Management Review Results - Primary Containment									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Downcomer Bracing and Supports	SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program-IWF Structures Monitoring Program	III.B1.2-10 III.A4-5	3.5.1-53 3.5.1-25	A A
2	Downcomer Bracing and Supports	SSR	Carbon Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	C 0509
3	Downcomer Jet Deflectors	HELB, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
4	Drywell Floor Decking	SSR	Galvanized Steel	Air - indoor	None	None	III.B1.1-7	3.5.1-58	C
5	Drywell Floor Peripheral Seal Assembly	DF, EN, EXP, SPB, SSR	Stainless Steel	Air - indoor	None	Inservice Inspection Program-IWE Appendix J Program	N/A	N/A	I 0501, 0502
6	Drywell Floor Peripheral Seal Jet Deflectors	HELB, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
7	Drywell Floor Shear Lugs	SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502

Table 3.5.2-1 Aging Management Review Results - Primary Containment									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
8	Drywell Head (including drywell head flanges, lifting lugs, support feet, and double o-rings)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502
9	Drywell Sump Liners	SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program BWR Water Chemistry Program	N/A	N/A	J 0508
10	Equipment Hatch and CRD Removal Hatch (including flange gaskets and closure mechanisms)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program Plant Technical Specification	II.B4-5 II.B4-6	3.5.1-17 3.5.1-18	A 0506
11	Penetrations (Mechanical and Electrical, primary containment boundary)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B4-1	3.5.1-18	A 0505
12	Penetrations (Mechanical and Electrical, primary containment boundary)	EN, SPB, SSR	Stainless Steel	Air - indoor	None	Inservice Inspection Program-IWE Appendix J Program	N/A	N/A	I 0501, 0505

Table 3.5.2-1 Aging Management Review Results - Primary Containment

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
13	Personnel Access Lock (including gaskets, hatch locks, hinges and closure mechanisms)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program Plant Technical Specification	II.B4-5 II.B4-6	3.5.1-17 3.5.1-18	A 0506
14	Pipe Whip Protection Support Rings	EN, PW, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
15	Primary Containment Vessel	EN, SPB, SRE, SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program -IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502
16	Primary Containment Vessel Inner and Outer Support Skirts	SPB, SSR	Carbon Steel	Concrete	None	None	VII.J-21	3.3.1-96	C
17	Quencher Support	SSR	Carbon Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	C 0509
18	Radial Beam Framing System	EN, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
19	Reactor Vessel Thermal Insulation	EN, PR, SSR	Stainless Steel/ Aluminum	Air - indoor	None	None	III.B1.1-9 III.B1.1-6	3.5.1-59 3.5.1-58	C C
20	Refueling Bellows Seals	EXP, FLB, SSR	Stainless Steel	Air - indoor	None	Structures Monitoring Program	III.B1.1-9	3.5.1-59	C 0501 0503

Table 3.5.2-1 Aging Management Review Results - Primary Containment

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
21	Refueling Bulkhead Seal Plate	FLB, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
22	Sacrificial Shield Wall Inner and Outer Skins (including removable plugs, shield doors, and removable panels)	EN, SHD, SNS, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
23	Sand Filled Pocket Area (including closure ring)	DF, FLB, SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502 0504
24	Stabilizer Truss	SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program-IWF Structures Monitoring Program	III.B.1.3-10 III.A4-5	3.5.1-53 3.5.1-25	A A
25	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SNS, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A4-5	3.5.1-25	A
26	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SNS, SSR	Galvanized Steel	Air - indoor	None	None	III.B1.1-7	3.5.1-58	C

Table 3.5.2-1 Aging Management Review Results - Primary Containment

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
27	Suppression Chamber (including vertical stiffeners and horizontal stiffener rings)	EN, HS, SPB, SRE, SSR	Carbon Steel	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502
28	Suppression Chamber (including vertical stiffeners and horizontal stiffener rings)	EN, HS, SPB, SRE, SSR	Carbon Steel	Treated water	Loss of material	Inservice Inspection Program-IWE Appendix J Program BWR Water Chemistry Program	II.B2.1-1	3.5.1-05	A 0502 0507
29	Suppression Chamber (bottom ellipsoidal head)	EN, HS, SPB, SRE, SSR	Carbon Steel	Concrete	None	None	VII.J-21	3.3.1-96	C
30	Suppression Chamber Access Hatch (including flange gaskets and closure mechanisms)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program Plant Technical Specification	II.B4-5 II.B4-6	3.5.1-17 3.5.1-18	A 0506
31	Concrete Under the Ellipsoidal Head	SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
32	Drywell Floor	EN, FLB, MB, SSR, SRE	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-1 Aging Management Review Results - Primary Containment									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
33	Drywell Floor Support Columns	SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
34	Drywell Floor Support Columns	SSR	Concrete	Treated water	None	Structures Monitoring Program	N/A	N/A	I 0501
35	Drywell Sumps	DF, FLB, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
36	Floor Trench	DF, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
37	Reactor Pedestal	SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
38	Reactor Pedestal	SSR	Concrete	Treated water	None	Structures Monitoring Program	N/A	N/A	I 0501
39	Reinforced Concrete Lining Inside the Bottom Head of the Primary Containment Vessel	SSR	Concrete	Treated water	None	Structures Monitoring Program	N/A	N/A	I 0501
40	Sacrificial Shield Wall	EN, MB, SHD, SNS, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
41	Sand Filled Pocket Area	DF, FLB, SSR	Concrete (w/ Sand)	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501 0504

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-2 Aging Management Review Results - Reactor Building									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Blowout Panels	SPB, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
2	Blowout Panels	SPB, SSR	Carbon Steel	Air - outdoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
3	Cranes, including Bridge, Trolley, Rails, and Girders	SNS, SSR	Carbon Steel	Air - indoor	Loss of material	Material Handling System Inspection Program	VII.B-3	3.3.1-73	A
4	Elevated Release Stack	RP, SSR	Carbon Steel	Air - outdoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
5	Lead Shield Panels	SHD, SNS	Stainless Steel	Air - indoor	None	None	III.B5-5	3.5.1-59	C 0516
6	Metal Siding	EN, SPB, SSR	Galvanized Steel	Air - indoor	None	None	III.B5-3	3.5.1-58	C
7	Metal Siding	EN, SPB, SSR	Galvanized Steel	Air - outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
8	New Fuel Racks	EN, SSR	Aluminum/ Stainless Steel fasteners	Air - indoor	None	None	III.B5-2 III.B5-5	3.5.1-58 3.5.1-59	C 0511 A 0511
9	Reactor Well and Dryer-Separator Storage Pool Gates	SSR	Aluminum	Air - indoor	None	None	III.B5-2	3.5.1-58	C
10	Reactor Well and Dryer-Separator Storage Pool Liners	SSR	Stainless Steel	Air - indoor	None	None	III.B5-5	3.5.1-59	C

Table 3.5.2-2 Aging Management Review Results - Reactor Building									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
11	Roof Decking	EN, SPB, SSR	Galvanized Steel	Air - indoor	None	None	III.B5-3	3.5.1-58	C
12	Roof Masts	SRE	Galvanized Steel	Air - outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
13	Secondary Containment Air Locks (includes railroad bay and double air lock doors)	MB, SPB, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
14	Secondary Containment Air Locks (includes railroad bay and double air lock doors)	MB, SPB, SSR	Carbon Steel	Air - outdoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
15	Spent Fuel Pool Gates	SSR	Aluminum	Air - indoor	None	None	III.B5-2	3.5.1-58	C
16	Spent Fuel Pool Gates	SSR	Aluminum	Treated water	Loss of material	BWR Water Chemistry Program	VII.A4-5	3.3.1-24	C 0513 0514

Table 3.5.2-2 Aging Management Review Results - Reactor Building

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
17	Spent Fuel Pool Liner	SSR	Stainless Steel	Treated water	Loss of material	BWR Water Chemistry Program Spent Fuel Pool Water Monitoring per Tech Spec Monitoring of leakage from the leak chase channels	III.A5-13	3.5.1-46	A 0512
18	Spent Fuel Storage Racks	SSR	Stainless Steel	Treated water	Loss of material	BWR Water Chemistry Program	VII.A4-11	3.3.1-24	C 0514
19	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR	Carbon Steel	Air - indoor	Loss of material	Structures Monitoring Program	III.A2-12	3.5.1-25	A
20	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR	Galvanized Steel	Air - indoor	None	None	III.B5-3	3.5.1-58	C
21	Sump Liners	SNS	Stainless Steel	Air - indoor	None	None	III.B5-5	3.5.1-59	C
22	Sump Liners	SNS	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0515
23	Biological Shield Wall	EN, MB, SHD, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-2 Aging Management Review Results - Reactor Building									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
24	Elevated Release Stack	RP, SSR	Concrete	Air - outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
25	Exterior Walls (above grade)	EN, MB, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
26	Exterior Walls (above grade)	EN, MB, SSR	Concrete	Air - outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
27	Exterior Walls (below grade)	EN, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
28	Foundations	EN, EXP, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
29	Main Steam Tunnel	EN, HELB, MB, PW, SHD, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
30	New Fuel Storage Vault and Cover	EN, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
31	Pipe Chase	EN, SHD, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
32	Pump Pits	SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
33	Refueling pools (spent fuel, reactor well, dryer-separator pools)	EN, SHD, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-2 Aging Management Review Results - Reactor Building

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
34	Reinforced Concrete: Walls, floors, and ceilings	EN, FB, FLB, HELB, MB, SHD, SNS, SRE, SSR	Concrete	Air - indoor	None	Structures Monitoring Program Fire Protection Program	N/A	N/A	I 0501
35	Shield Plugs	EN, SHD, SSR	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
36	Shield Walls	SHD, SNS	Concrete (solid blocks or bricks)	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501 0517
37	Sumps	SNS	Concrete	Air - indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
38	Spent Fuel Rack Neutron Absorbers	ABN, SSR	Boron Carbide		None	None	N/A	N/A	J 0510
			Stainless Steel (sheathing)	Treated water	Loss of material	BWR Water Chemistry Program	VII.A4-11	3.3.1-24	C 0510 0514

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-3 Aging Management Review Results – Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Bulkhead Fixed Screens	SRE, SSR	Stainless Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
2	Bulkhead Fixed Screen Frames	SRE, SSR	Galvanized Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
3	Bulkhead Screen Guides	SRE, SSR	Carbon Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
4	Spray pond circular header supports	SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Inservice Inspection Program-IWF Structures Monitoring Program – Water Control Structures Inspection	III.B1.3-10 III.A6-11	3.5.1-53 3.5.1-47	A E 0518
5	Spray pond circular header supports	SRE, SSR	Carbon Steel	Raw water	Loss of material	Inservice Inspection Program-IWF Structures Monitoring Program – Water Control Structures Inspection	III.B1.3-10 III.A6-11	3.5.1-53 3.5.1-47	A E 0518

Table 3.5.2-3 Aging Management Review Results – Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
6	Spray pond circular header supports	SRE, SSR	Teflon (Fluorogold®)	Air-outdoor	Cracking	Inservice Inspection Program-IWF Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	J 0518
7	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
8	Barrier Skimmer Wall	SRE, SSR	Concrete	Water-flowing	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519
9	Foundations	EN, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501, 0518
10	Pump Intake Chambers	SCW, SRE, SSR	Concrete	Water-flowing	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519
11	Reinforced Concrete: Walls, floors, and ceilings	EN, MB, SNS, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518

Table 3.5.2-3	Aging Management Review Results – Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B								
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
12	Roof Slabs	EN, MB, SNS, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
13	Spray Pond Depressed Sump	EN, HS, SCW, SRE, SSR	Concrete	Raw water	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518 0520
14	Spray Pond Foundation	EN, HS, SCW, SRE, SSR	Concrete	Raw water	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518 0520
15	Spray Pond Foundation	EN, HS, SCW, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
16	Spray Pond Sand Trap	EN, HS, SCW, SRE, SSR	Concrete	Raw water	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518 0520
17	Spray Pond Walls (below grade)	EN, HS, SCW, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
18	Spray Pond Walls (above grade)	EN, HS, SCW, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518

Table 3.5.2-3 Aging Management Review Results – Standby Service Water Pump House 1A and 1B and Spray Pond 1A and 1B

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
19	Spray Pond Walls	EN, HS, SCW, SRE, SSR	Concrete	Water-flowing	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519
20	Standby Service Water Pump House Exterior Walls (above grade)	EN, MB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
21	Standby Service Water Pump House Exterior Walls (below grade)	EN, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
22	Sumps	SNS	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
23	Sumps	SNS	Concrete	Raw water	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-4	Aging Management Review Results - Circulating Water Pump House								
Row No.	**Component / Commodity**	**Intended Function**[1]	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Battery Racks	SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
2	Bulkhead Screen Frames	SRE	Galvanized Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
3	Bulkhead Screens	SRE	Stainless Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
4	Bulkhead Screen Guides	SRE	Carbon Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
5	Metal Siding	SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
6	Roof Decking	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
7	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518

Table 3.5.2-4	Aging Management Review Results - Circulating Water Pump House								
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
8	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
9	Foundation	SRE	Concrete	Water-flowing	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519
10	Foundation	SRE	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
11	Reinforced Concrete: Walls, floors, and ceilings	SRE	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
12	Masonry Block Walls	FB, SRE	Concrete Blocks	Air-indoor	Cracking	Structures Monitoring Program – Masonry Wall Inspection Fire Protection Program	III.A6-10 III.A6-10	3.5.1-43 3.5.1-43	A E

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-5	Aging Management Review Results – Diesel Generator Building								
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Battery Racks	SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
2	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
3	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
4	Diesel Generator Exhaust Plenums	EN, MB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
5	Diesel Generator Intake Plenums	EN, MB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
6	Diesel Generator Pedestals	EXP, EN, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
7	Exterior Walls (above grade)	EN, MB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
8	Foundations	EN, EXP, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
9	Reinforced Concrete: Walls, floors, and ceilings	EN, FB, MB, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program Fire Protection Program	N/A	N/A	I 0501

Table 3.5.2-5 Aging Management Review Results – Diesel Generator Building

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
10	Roof	EN, MB, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501 0526

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-6	Aging Management Review Results – Fresh Air Intake Structure No. 1 and 2								
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Concrete Air Plenum	EN, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
2	Exterior Walls (above grade)	EN, MB, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
3	Exterior Walls (below grade)	EN, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
4	Foundations	EN, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
5	Roof	EN, MB, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-7 Aging Management Review Results – Makeup Water Pump House									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
2	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
3	Exterior Walls (above grade)	MB, SNS	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
4	Pump Pit	SNS	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
5	Foundations	SNS	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
6	Reinforced Concrete: Walls, floors, and ceilings	SNS	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518
7	Roof	MB, SNS	Concrete	Air-indoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501 0518 0526

Table 3.5.2-7 Aging Management Review Results – Makeup Water Pump House									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1 Refer to Table 2.0-1 for intended function descriptions.									

Table 3.5.2-8 Aging Management Review Results – Radwaste Control Building									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Battery Racks	SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
2	Control Room Ceiling	SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A1-12	3.5.1-25	A
3	Metal Siding	SNS	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
4	Partition Walls	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
5	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR, SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A1-12	3.5.1-25	A
6	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	EN, SSR, SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
7	Sump Liners	SNS	Stainless Steel	Air-indoor	None	None	III.B5-5	3.5.1-59	C
8	Exterior Walls (above grade)	EN, MB, SHD, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
9	Foundations	EN, EXP, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-8 Aging Management Review Results – Radwaste Control Building

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
10	Masonry Block Walls	FB, SHD, SRE	Concrete Blocks	Air-indoor	Cracking	Structures Monitoring Program – Masonry Wall Inspection	III.A3-11	3.5.1-43	A
						Fire Protection Program	III.A3-11	3.5.1-43	E
11	Reinforced Concrete: Walls, floors, and ceilings	EN, FB, SHD, SPB, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program Fire Protection Program	N/A	N/A	I 0501
12	Reinforced Concrete: Walls, floors, and ceilings (Radwaste Control Building Zone E at el. 437'-0" and Zone K at el. 467' 0")	EN, FB, SHD, SPB, SRE, SSR	Concrete	Air-indoor	Cracking Change in material properties	Structures Monitoring Program Fire Protection Program	N/A	N/A	H 0521
13	Roof	EN, MB, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501 0526
14	Sumps	SNS	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-9 Aging Management Review Results – Service Building									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Roof Decking	SNS	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
2	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
3	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
4	Exterior Walls (above grade)	EN, SNS	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
5	Foundations	EN, EXP, SNS	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
6	Reinforced Concrete: Walls, floors, and ceilings	EN, SNS	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-10 Aging Management Review Results – Turbine Generator Building

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Metal Siding	SRE, SNS	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
2	Roof Decking	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
3	Shield Walls	MB	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C 0517
4	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS, SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
5	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SNS, SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
6	Sump Liners	SNS	Stainless Steel	Air-indoor	None	None	III.B5-5	3.5.1-59	C
7	Sump Liners	SNS	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0515
8	Exterior Walls (above grade)	EN, SNS, SRE	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
9	Foundations	EN, EXP, SNS, SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
10	Main Steam Tunnel Extension	EN, HELB, MB, PW, SHD, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-10 Aging Management Review Results – Turbine Generator Building									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
11	Masonry Block Walls	EN, FB, SRE	Concrete Blocks	Air-indoor	Cracking	Structures Monitoring Program – Masonry Wall Inspection	III.A3-11	3.5.1-43	A
						Fire Protection Program	III.A3-11	3.5.1-43	E
12	Reinforced Concrete: Walls, floors, and ceilings	EN, FB, SNS, SRE	Concrete	Air-indoor	None	Structures Monitoring Program Fire Protection Program	N/A	N/A	I 0501
13	Shield Walls	EN, MB, SHD	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
14	Shield Walls	EN, MB, SHD	Concrete (solid blocks or bricks)	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501 0517
15	Sumps	SNS	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
16	Turbine Generator Pedestals	EN, SRE, SNS	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-11	Aging Management Review Results – Water Filtration Building								
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Battery Racks	SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
2	Metal Siding	SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
3	Roof Decking	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
4	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
5	Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
6	Foundations	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
7	Sumps	SRE	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-12 Aging Management Review Results – Yard Structures									
Row No.	**Component/Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
1	Ashe Relay House Metal Siding	SRE	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
2	Ashe Relay House Roof Decking	SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
3	Ashe Relay House Roof Decking	SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
4	Ashe Relay House Structural Steel: Beams, Columns, Plates, and Trusses (includes welds and bolted connections)	SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
5	Fire Water Bladder Tank (FP-TK-110) Vent Line Enclosure	SRE	Aluminum	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0522
6	Manhole Covers	EN, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.A3-12	3.5.1-25	A
7	Transmission Towers	SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
8	Weir Box	SRE	Carbon Steel	Water-flowing	Loss of material	Structures Monitoring Program – Water Control Structures Inspection	III.A6-11	3.5.1-47	E 0518
9	Ashe Relay House Foundation	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-12	Aging Management Review Results – Yard Structures								
Row No.	**Component/Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
10	Circulating Water Basin	SNS, SRE	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501
11	Circulating Water Basin	SNS, SRE	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501
12	Circulating Water Basin	SNS, SRE	Concrete	Raw water	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519 0520
13	Condensate Storage Tank Foundation (ring wall)	SNS, SRE	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
14	Condensate Storage Tank Retaining Area (slab)	FLB, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
15	Condensate Storage Tank Retaining Area (slab)	FLB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
16	Condensate Storage Tank Retaining Area (walls)	FLB, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
17	Cooling Tower Basins	SNS	Concrete	Soil	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501
18	Cooling Tower Basins	SNS	Concrete	Air-outdoor	None	Structures Monitoring Program – Water Control Structures Inspection	N/A	N/A	I 0501

Table 3.5.2-12 Aging Management Review Results – Yard Structures

Row No.	Component/Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
19	Cooling Tower Basins	SNS	Concrete	Raw water	Loss of material Cracking	Structures Monitoring Program – Water Control Structures Inspection	III.A6-5	3.5.1-35	E 0518 0519 0520
20	Duct banks	EN, SNS, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
21	Fire Water Bladder Tank (FP-TK-110) Embankment Apron	SRE	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
22	Fire Water Bladder Tank (FP-TK-110) Support Pads	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
23	HSSF Liquid Hydrogen Storage Tank Foundation (slab)	SNS	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
24	HSSF Liquid Hydrogen Storage Tank Foundation (raised pedestals)	SNS	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
25	Manholes	EN, SNS, SRE, SSR	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
26	Manholes	EN, SNS, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
27	Thrust Blocks	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
28	Transformer/ Breaker Foundations (SBO)	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-12 Aging Management Review Results – Yard Structures

Row No.	Component/Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
29	Transformer/ Breaker Foundations (SBO)	SRE	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
30	Transmission Tower Foundations	SRE	Concrete	Soil	None	Structures Monitoring Program	N/A	N/A	I 0501
31	Transmission Tower Foundations	SRE	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
32	Fire Water Bladder Tank (FP-TK-110) Embankment	SRE	Earthen	Air-outdoor	Loss of form	Structures Monitoring Program	N/A	N/A	G

1 Refer to Table 2.0-1 for intended function descriptions.

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Steel and Other Metals									
1	Anchorage/Embedments	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
2	Anchorage/Embedments	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5 III.B3-3 III.B4-5 III.B5-3	3.5.1-58	A
3	Anchorage/Embedments	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B3-5 III.B4-8 III.B5-5	3.5.1-59	A
4	Anchorage/Embedments	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
5	Anchorage/Embedments	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	A
6	Anchorage/Embedments	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	I 0525
7	Anchorage/Embedments	SNS, SRE, SSR	Carbon Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
8	Anchorage/Embedments	SNS, SRE, SSR	Galvanized Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
9	Anchorage/Embedments	SNS, SRE, SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0524
10	Cable Tie Wraps	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B3-5 III.B4-8 III.B5-5	3.5.1-59	C
11	Cable Tray and Conduit Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
12	Cable Tray and Conduit Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	A
13	Cable Tray and Conduit Supports	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
14	Cable Tray and Conduit Supports	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	A
15	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Aluminum	Air-indoor	None	None	III.B3-2	3.5.1-58	C
16	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
17	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
18	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Aluminum	Air-outdoor	None	Structures Monitoring Program	III.B2-7	3.5.1-50	I 0525
19	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
20	Cable Trays and Conduits	EN, FB, SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
21	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Inservice Inspection Program-IWF	III.B1.1-13 III.B1.2-10 III.B1.3-10	3.5.1-53	A
22	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B1.1-7 III.B1.2-5 III.B1.3-5	3.5.1-58	A
23	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B1.1-9 III.B1.2-7 III.B1.3-7	3.5.1-59	A
24	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Inservice Inspection Program-IWF	III.B1.2-10	3.5.1-53	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
25	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Inservice Inspection Program-IWF	III.B1.2-10	3.5.1-53	A
26	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Carbon Steel	Raw water	Loss of material	Inservice Inspection Program-IWF	III.A6-11	3.5.1-47	E
27	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Galvanized Steel	Raw water	Loss of material	Inservice Inspection Program-IWF	III.A6-11	3.5.1-47	E
28	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Carbon Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	A
29	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Galvanized Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	A
30	Component and Piping Supports (ASME Class 1, 2, 3 and MC)	SRE, SSR	Stainless Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
31	Damper Framing (in-wall)	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
32	Damper Framing (in-wall)	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	C
33	Electrical and Instrument Panels & Enclosures	EN, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
34	Electrical and Instrument Panels & Enclosures	EN, SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B3-3	3.5.1-58	C
35	Electrical and Instrument Panels & Enclosures	EN, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
36	Electrical and Instrument Panels & Enclosures	EN, SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
37	Electrical Bus Ducts	EN, SRE, SSR	Aluminum	Air-indoor	None	None	III.B3-2	3.5.1-58	C
38	Electrical Bus Ducts	EN, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	VI.A-13	3.6.1-09	A
39	Electrical Bus Ducts	EN, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B3-3	3.5.1-58	C
40	Electrical Bus Ducts	EN, SRE, SSR	Aluminum	Air-outdoor	None	Structures Monitoring Program	III.B2-7	3.5.1-50	I 0525
41	Electrical Bus Ducts	EN, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	VI.A-13	3.6.1-09	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
42	Electrical Bus Ducts	EN, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	VI.A-13	3.6.1-09	A
43	Equipment Component Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
44	Equipment Component Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5 III.B3-3 III.B4-5 III.B5-3	3.5.1-58	A
45	Equipment Component Supports	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B3-5 III.B4-8 III.B5-5	3.5.1-59	A
46	Equipment Component Supports	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
47	Equipment Component Supports	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	A
48	Equipment Component Supports	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	I 0525

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
49	Flood Curbs	FLB, SNS	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	C
50	Flood, Pressure, and Specialty Doors	FLB, MB, PB, SHD, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B4-10	3.5.1-39	C
51	Flood, Pressure, and Specialty Doors	FLB, MB, PB, SHD, SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B4-5	3.5.1-58	C
52	Flood, Pressure, and Specialty Doors	FLB, MB, PB, SHD, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B4-10	3.5.1-39	C
53	Flood, Pressure, and Specialty Doors	FLB, MB, PB, SHD, SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B4-7	3.5.1-50	C
54	Hatches	EN, FB, FLB, MB, PB, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B4-10	3.5.1-39	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
55	Hatches	EN, FB, FLB, MB, PB, SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B4-5	3.5.1-58	C
56	Hatches	EN, FB, FLB, MB, PB, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B4-10	3.5.1-39	C
57	Hatches	EN, FB, FLB, MB, PB, SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B4-7	3.5.1-50	C
58	HELB Barriers (includes pipe restraints, whip restraints, and jet/missile impingement shields/plate barriers)	HELB, PW, SNS, SSR	Aluminum	Air-indoor	None	None	III.B5-2	3.5.1-58	C
59	HELB Barriers (includes pipe restraints, whip restraints, and jet/missile impingement shields/plate barriers)	HELB, PW, SNS, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
60	HELB Barriers (includes pipe restraints, whip restraints, and jet/missile impingement shields/plate barriers)	HELB, PW, SNS, SSR	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
61	HELB Barriers (includes pipe restraints, whip restraints, and jet/missile impingement shields/plate barriers)	HELB, PW, SNS, SSR	Stainless Steel	Air-indoor	None	None	III.B5-5	3.5.1-59	C
62	HELB Barriers (includes pipe restraints, whip restraints, and jet/missile impingement shields/plate barriers)	HELB, PW, SNS, SSR	Stainless Steel	Treated water	Loss of material	Structures Monitoring Program BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	E 0534
63	HVAC Duct Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
64	HVAC Duct Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
65	HVAC Duct Supports	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8	3.5.1-59	A
66	Instrument Line Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
67	Instrument Line Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	A
68	Instrument Line Supports	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8	3.5.1-59	A
69	Instrument Line Supports	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
70	Instrument Line Supports	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	A
71	Instrument Line Supports	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7	3.5.1-50	I 0525
72	Instrument Racks and Frames	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
73	Instrument Racks and Frames	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B3-3	3.5.1-58	C
74	Instrument Racks and Frames	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B3-7	3.5.1-39	C
75	Instrument Racks and Frames	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
76	Monorails, Hoists and Miscellaneous Cranes	SNS	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
77	Penetrations (Mechanical and Electrical, non primary containment boundary)	EN, FB, FLB, PB, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
78	Pipe Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B4-10	3.5.1-39	A
79	Pipe Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5 III.B4-5	3.5.1-58	A
80	Pipe Supports	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B4-8	3.5.1-59	A
81	Pipe Supports	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B4-10	3.5.1-39	A
82	Pipe Supports	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	A
83	Pipe Supports	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	I 0525
84	Pipe Supports	SNS, SRE, SSR	Carbon Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
85	Pipe Supports	SNS, SRE, SSR	Galvanized Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
86	Pipe Supports	SNS, SRE, SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0524

Table 3.5.2-13		Aging Management Review Results – Bulk Commodities							
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
87	Pipe Supports	SNS, SRE, SSR	Carbon Steel	Treated water	Loss of material	Structures Monitoring Program BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	E
88	Pipe Supports	SNS, SRE, SSR	Stainless Steel	Treated water	Loss of material	Structures Monitoring Program BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	E
89	Stair, Ladder, Platform, and Grating Supports	SNS, SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	A
90	Stair, Ladder, Platform, and Grating Supports	SNS, SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	A
91	Stair, Ladder, Platform, and Grating Supports	SNS, SRE	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	A
92	Stair, Ladder, Platform, and Grating Supports	SNS, SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	A
93	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Aluminum	Air-indoor	None	None	III.B5-2	3.5.1-58	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
94	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	C
95	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Galvanized Steel	Air-indoor	None	None	III.B5-3	3.5.1-58	C
96	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Aluminum	Air-outdoor	None	Structures Monitoring Program	III.B4-7	3.5.1-50	I 0525
97	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B5-7	3.5.1-39	C
98	Stairs, Ladders, Platforms, and Gratings	SNS, SRE	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
99	Tube Track Supports	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
100	Tube Track Supports	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	A
101	Tube Track Supports	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	A
102	Tube Track Supports	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	A
103	Tube Tracks	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
104	Tube Tracks	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
105	Vents and Louvers	SNS, SRE, SSR	Aluminum	Air-indoor	None	None	III.B2-4	3.5.1-58	C
106	Vents and Louvers	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
107	Vents and Louvers	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5	3.5.1-58	C
108	Vents and Louvers	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8	3.5.1-59	C
109	Vents and Louvers	SNS, SRE, SSR	Aluminum	Air-outdoor	None	Structures Monitoring Program	III.B2-7	3.5.1-50	I 0525
110	Vents and Louvers	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10	3.5.1-39	C
111	Vents and Louvers	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7	3.5.1-50	C
112	Vents and Louvers	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7	3.5.1-50	I 0525
Threaded Fasteners									
113	Anchor Bolts	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
114	Anchor Bolts	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5 III.B3-3 III.B4-5 III.B5-3	3.5.1-58	A
115	Anchor Bolts	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B3-5 III.B4-8 III.B5-5	3.5.1-59	A
116	Anchor Bolts	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
117	Anchor Bolts	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	A
118	Anchor Bolts	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	I 0525
119	Anchor Bolts	SNS, SRE, SSR	Carbon Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
120	Anchor Bolts	SNS, SRE, SSR	Galvanized Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
121	Anchor Bolts	SNS, SRE, SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0524

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
122	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Inservice Inspection Program-IWF	III.B1.1-13 III.B1.2-10 III.B1.3-10	3.5.1-53	A
123	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B1.1-7 III.B1.2-5 III.B1.3-5	3.5.1-58	A
124	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B1.1-9 III.B1.2-7 III.B1.3-7	3.5.1-59	A
125	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Inservice Inspection Program-IWF	III.B1.2-10	3.5.1-53	A
126	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Inservice Inspection Program-IWF	III.B1.2-10	3.5.1-53	E
127	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Carbon Steel	Raw water	Loss of material	Inservice Inspection Program-IWF	III.A6-11	3.5.1-47	E
128	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Galvanized Steel	Raw water	Loss of material	Inservice Inspection Program-IWF	III.A6-11	3.5.1-47	E

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
129	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Carbon Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	A
130	Anchor Bolts (ASME Class 1, 2, 3 and MC Supports Bolting)	SRE, SSR	Stainless Steel	Treated water	Loss of material	Inservice Inspection Program-IWF BWR Water Chemistry Program	III.B1.1-11	3.5.1-49	A
131	Expansion Anchors	SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
132	Expansion Anchors	SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	None	III.B2-5 III.B3-3 III.B4-5 III.B5-3	3.5.1-58	A
133	Expansion Anchors	SNS, SRE, SSR	Stainless Steel	Air-indoor	None	None	III.B2-8 III.B3-5 III.B4-8 III.B5-5	3.5.1-59	A

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
134	Expansion Anchors	SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-10 III.B3-7 III.B4-10 III.B5-7	3.5.1-39	A
135	Expansion Anchors	SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	A
136	Expansion Anchors	SNS, SRE, SSR	Stainless Steel	Air-outdoor	None	Structures Monitoring Program	III.B2-7 III.B4-7	3.5.1-50	I 0525
137	Expansion Anchors	SNS, SRE, SSR	Carbon Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
138	Expansion Anchors	SNS, SRE, SSR	Galvanized Steel	Raw water	Loss of material	Structures Monitoring Program	III.A6-11	3.5.1-47	E
139	Expansion Anchors	SNS, SRE, SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program	VII.C3-7	3.3.1-78	E 0524
Concrete									
140	Equipment Pads	SNS, SRE, SSR	Concrete	Air-indoor	Cracking Change in material properties	Structures Monitoring Program	N/A	N/A	H 0521
141	Equipment Pads	SNS, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
142	Flood Curbs	FLB, SNS	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501

Table 3.5.2-13	Aging Management Review Results – Bulk Commodities								
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
143	Floor Trenches	SNS, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
144	Hatches	EN, FB, FLB, MB, PB, SHD, SNS, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
145	Hatches	EN, FB, FLB, MB, PB, SHD, SNS, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
146	Support Pedestals	SNS, SRE, SSR	Concrete	Air-indoor	None	Structures Monitoring Program	N/A	N/A	I 0501
147	Support Pedestals	SNS, SRE, SSR	Concrete	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	I 0501
148	Support Pedestals	SNS, SRE, SSR	Concrete	Raw water	Loss of material Cracking	Structures Monitoring Program	III.A6-5	3.5.1-35	E 0519
				Elastomeric Components					
149	Biological Shield Wall Annulus Compressible Material	EXP, SSR	Elastomer	Air-indoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0528

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
150	Building Pressure Boundary Seals and Sealants	EXP, PB, SNS, SSR	Elastomer	Air-indoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0528
151	Compressible Joints and Seals	EXP, FLB, SNS, SSR	Elastomer	Air-indoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0528
152	Compressible Joints and Seals	EXP, FLB, SNS, SSR	Elastomer	Air-outdoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0529
153	Expansion Boots	EXP, FLB, SNS, SRE, SSR	Elastomer	Air-outdoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0529
154	Expansion Boots	EXP, FLB, SNS, SRE, SSR	Elastomer	Soil	None	None	N/A	N/A	J

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
155	Roof Membrane	EN, FLB, SNS, SRE, SSR	Elastomer/ Built-up Roofing	Air-outdoor	Cracking Change in material properties	Structures Monitoring Program	III.A6-12	3.5.1-44	C 0527 0529
156	Waterproofing Membrane	FLB, SNS, SSR	Elastomer	Soil	None	None	N/A	N/A	J
157	Waterstops	FLB, SNS, SSR	Elastomer	Air-indoor (within walls, floors, or foundations)	None	None	N/A	N/A	J
158	Waterstops	FLB, SNS, SSR	Elastomer	Soil	None	None	N/A	N/A	J
Fire Barriers									
159	Fire Doors	FB, SNS, SRE, SSR	Carbon Steel	Air-indoor	Loss of material	Fire Protection Program	VII.G-3	3.3.1-63	B 0530
						Structures Monitoring Program	III.B4-10	3.5.1-39	C
160	Fire Doors	FB, SNS, SRE, SSR	Galvanized Steel	Air-indoor	None	Fire Protection Program	N/A	N/A	I 0501
						Structures Monitoring Program	III.B4-5	3.5.1-58	C

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
161	Fire Doors	FB, SNS, SRE, SSR	Carbon Steel	Air-outdoor	Loss of material	Fire Protection Program	VII.G-4	3.3.1-63	B 0530
						Structures Monitoring Program	III.B4-10	3.5.1-39	C
162	Fire Doors	FB, SNS, SRE, SSR	Galvanized Steel	Air-outdoor	Loss of material	Fire Protection Program	VII.G-4	3.3.1-63	B 0530
						Structures Monitoring Program	III.B4-7	3.5.1-50	C
163	Fire Stops	FB, FLB, PB, SNS, SRE, SSR	Silicone Elastomer	Air-indoor	Cracking/ Delamination/ Separation Change in material properties	Fire Protection Program	VII.G-1	3.3.1-61	B 0528
164	Fireproofing	FB, SNS, SRE, SSR	Thermolag	Air-indoor	None	Fire Protection Program	N/A	N/A	J 0501
165	Fire Wraps	SNS, SRE, SSR	Ceramic fiber	Air-indoor	None	Fire Protection Program	N/A	N/A	J 0501 0534
166	Fire Wraps	FB, SNS, SRE, SSR	Darmatt	Air-indoor	None	Fire Protection Program	N/A	N/A	J 0501

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
167	Fire Wraps	FB, SNS, SRE, SSR	Thermolag	Air-indoor	None	Fire Protection Program	N/A	N/A	J 0501
168	Fire Wraps	FB, SNS, SRE, SSR	3M Interam	Air-indoor	None	Fire Protection Program	N/A	N/A	J 0501
Fluoropolymers and Lubrite Sliding Surfaces									
169	Cable Tie Wraps	SNS, SRE, SSR	Fluoropolymer	Air-indoor	None	None	N/A	N/A	J 0531
170	Cable Tie Wraps	SNS, SRE	Nylon	Air-indoor	None	None	N/A	N/A	J 0532
171	Lubrite sliding supports	SNS, SSR	Lubrite	Air-indoor	None	Inservice Inspection Program-IWF Structures Monitoring Program	III.B1.1-5 III.B1.2-3 III.B1.3-3 III.B2-2	3.5.1-56 3.5.1-52.	I 0523 I 0523
Miscellaneous Materials									
172	Containment Penetration Insulation	SNS	Fiberglass	Air-indoor	None	None	N/A	N/A	J
173	Piping and Mechanical equipment Insulation	SNS	Aluminum jacketing	Air-indoor	None	None	N/A	N/A	J

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
174	Piping and Mechanical equipment Insulation	SNS	Calcium Silicate	Air-indoor	None	None	N/A	N/A	J
175	Piping and Mechanical equipment Insulation	SNS	Fiberglass	Air-indoor	None	None	N/A	N/A	J
176	Piping and Mechanical equipment Insulation	SNS	Stainless Steel Mirror insulation	Air-indoor	None	None	N/A	N/A	J
177	Piping and Mechanical equipment Insulation	SNS	Aluminum jacketing	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	J 0525
178	Piping and Mechanical equipment Insulation	SNS	Calcium Silicate	Air-outdoor	None	None	N/A	N/A	J
179	Piping and Mechanical equipment Insulation	SNS	Fiberglass	Air-outdoor	None	None	N/A	N/A	J
180	Piping and Mechanical equipment Insulation	SNS	Stainless Steel Mirror insulation	Air-outdoor	None	Structures Monitoring Program	N/A	N/A	J 0525

Table 3.5.2-13 Aging Management Review Results – Bulk Commodities

Row No.	Component / Commodity	Intended Function[1]	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes

1 - Refer to Table 2.0-1 for intended function descriptions.

Generic Notes:	
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-Specific Notes:	
0501	No applicable aging effects have been identified for the component type. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0502	NUREG-1801 item II.B2.1-1 indicates the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements. Columbia drywell floor peripheral seal is made of stainless steel and is welded to the primary containment vessel and to the underside of the circular closure girder embedded in the drywell floor. There are no concrete to metal moisture barriers; therefore, the NUREG-1801 text regarding moisture barrier is not applicable.
0503	The refueling stainless steel bellows perform their functions during refueling preventing water from entering the drywell. The bellows are not subjected to cyclic loading during refueling. The normal environment experienced by the refueling bellows is warm, dry air, with short periods of demineralized water contact during refueling.
0504	Due to possibility of containment shell degradation from corrosion induced by a moist environment in sand pocket region, Columbia has committed to monitor humidity levels in this region. Columbia has implemented a procedure to survey the relative humidity of air drawn from within containment annulus sand pocket region.
0505	The process line penetrations are of welded steel construction without expansion bellows, gaskets, or sealing compounds. Electrical penetration assembly internal o-rings are sub-component of the electrical penetration and are included in this commodity group. Insulation for hot penetrations is addressed in bulk commodities.
0506	Elastomeric seals, gaskets, or o-rings are sub-part of the host component and their leak tightness is monitored by the Appendix J Program. Plant Technical Specification ensures that access airlocks and hatches maintain leak tightness in the closed position.
0507	In addition to Inservice Inspection Program-IWE and Appendix J Program as AMP, the BWR Water Chemistry Program is credited with the elimination of excessive chlorides and sulfates from the water.
0508	In addition to Structures Monitoring Program as AMP, the BWR Water Chemistry Program is credited with the elimination of excessive chlorides and sulfates from the water.
0509	Note C is used since NUREG-1801 only has an ASME Class 1 item for component in treated water. Component is ASME Class 2; the NUREG-1801 item is the closest match.

Plant-Specific Notes:	
0510	Aging management for loss of material of the neutron absorber stainless steel sheathing is required by the listed AMP. Columbia plant-specific AMR concluded boron carbide plates (B4C) do not require aging management for the period of extended operation for their neutron absorbing function based on plant-specific examination and industry operating experience. However, Columbia has already committed in the CLB to perform boron carbide coupon sample testing and this current commitment will continue to verify the specific design values of the B4C neutron absorbing parameters and demonstrate that the effects of aging are not significant. FSAR Section 9.1.2.3.2 states the CLB commitment, "To ensure the integrity of the spent fuel storage racks in the event that water has leaked into the racks, specially designed control samples, consisting of B4C plates in vented (to pool water) canisters, are placed in a readily accessible position in the spent fuel pool. These samples are subjected to periodic examinations to check for possible deterioration and they are also analyzed to ensure that the boron has not leached from the plates." The current CLB commitment along with continued monitoring of industry operating experience will provide adequate assurance that any age related degradation of the B4C will be detected.
0511	The new fuel storage racks are located in a dry mild environment inside the new fuel storage vault. The new fuel storage racks are made from aluminum with stainless steel fasteners. The use of stainless steel fasteners in aluminum to avoid detrimental galvanic corrosion in a predominantly air environment, is a recommended practice and has been used successfully for many years by the aluminum industry.
0512	The AMP manages loss of material due to crevice and pitting corrosion. Cracking due to SCC is not applicable. Spent fuel pool water level monitoring is per Technical Specifications. Leak chase channel monitoring is via operator rounds.
0513	The gates experience the same environment as the spent fuel pool liner. The BWR Water Chemistry Program manages Loss of material due to crevice and pitting corrosion. Cracking due to SCC is not applicable. Since the gates are part of the fuel pool water containment boundary, monitoring of fuel pool level and leak chase channels activities also indirectly manage this component.
0514	This NUREG-1801 item specifies the AMP is to be augmented by a "One-Time Inspection." Augmented One-time inspection is not applicable to the spent fuel pool since it is not a low flow or stagnant flow area. Also, NUREG-1801 Chapter VII.A2 Spent Fuel Storage does not require Water Chemistry to be augmented by a "One-Time Inspection." Augmented inspection applies to piping, piping components, and piping elements, not the spent fuel racks or gates.
0515	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. Chapter II or Chapter III of NUREG-1801 does not list exposed to raw water environment for stainless steel components. The identified AMP is used to manage aging effects for the period of extended operation.
0516	The lead panels are encapsulated within stainless steel casing.
0517	The shield walls at Columbia are made up of free-standing or stacked solid bricks (blocks) sandwiched between metal (siding) panels. The panel sections (and blocks) are held in place under all load conditions by angle sections anchored to the concrete wing walls at the pipe chases. Concrete block shield walls do not function like a typical block wall within a structure and are not subjected to degradations found from industry experience (i.e., aging effects cited in IEB 80-11.)

Plant-Specific Notes:	
0518	Columbia is not committed to RG 1.127 Inspection of Water Control Structures Associated with Nuclear Power Plants, Revision 1. However, the Structures Monitoring Program will be enhanced to include the inspection elements delineated in RG 1.127, Revision 1 per NUREG-1801 Chapter XI.S7.
0519	The NUREG-1801 item for freeze-thaw does not list exposed to raw water environment for water-control structures. Freeze-thaw can be possible near the water line. This environment is both exposed to weather and exposed to raw water; therefore, the environment is a match. The identified AMP is used to manage aging effects for the period of extended operation.
0520	Concrete component submerged in raw water is not susceptible to freeze-thaw. No applicable aging effects have been identified for the component type. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0521	The indicated aging effects (cracking and change in material properties due to irradiation) requiring management are only applicable to component types within the Radwaste Control Building charcoal absorber zones (i.e., Zone E at el. 437'-0" and Zone K at elevation 467'-0"). Radiation values are the worst case surface (contact) doses for the indicated zones. The identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0522	Loss of material due to crevice corrosion and pitting corrosion is not an aging effect requiring management for aluminum exposed to air-outdoor since Columbia is located in an in-land rural environment and not exposed to aggressive environmental conditions. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0523	Lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed. There are no known aging effects that would lead to a loss of intended function. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0524	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. NUREG-1801 does not list exposed to raw water environment for support components. The identified AMP is used to manage aging effects for the period of extended operation.
0525	The NUREG-1801 item lists Loss of material as an aging effect. This aging effect was determined not applicable since Columbia is located in an in-land rural environment and is not exposed to aggressive environmental conditions. Component external surfaces are not continuously wetted or exposed to an aggressive ambient environment (such as a saltwater atmosphere, sulfur dioxide, etc.) or industrial locations. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0526	The roof is insulated or has built-up roofing. Therefore, environment for this concrete roof slab is "air-indoor" for underside of slab. Roof membrane is evaluated and addressed in bulk commodities.

Plant-Specific Notes:	
0527	NUREG-1801 lists loss of sealing aging effect for elastomer. Loss of sealing is not an aging effect, but rather a consequence of elastomer degradation. This effect can be caused by cracking or change in material properties for elastomeric material. Note C is used since the NUREG-1801 item is intended for Group 6 - water-control structures' components; the line item covers all in-scope structures.
0528	Ionizing radiation is an applicable aging mechanism for elastomers located in areas where the radiation exceeds threshold. Ionizing radiation mechanism does not apply to elastomers located in mild radiation areas.
0529	Cracking and Change in material properties due to ultraviolet radiation and ozone are applicable aging effects for rubber only.
0530	The aging mechanism Loss of material due to wear is not an aging effect for fire doors based on EPRI Report 1015078 "Aging Effects for Structures and Structural Components (Structural Tools)." The aging mechanism Loss of material due to general corrosion was not specified in the corresponding NUREG-1801 item as an aging effect requiring management. Generic Note "A" was used to align to the NUREG-1801 item since the material, environment, aging effect, and program matches. The identified AMP will be used to manage Loss of material due to general corrosion and will confirm the absence of significant wear of fire doors for the period of extended operation. The Fire Protection Program inspects for excessive wear of latches, strike plates, hinges, sills, and closing devices, and proper clearances (gaps) between the door, frame, and threshold.
0531	Plant-specific Tefzel tie wraps test report and engineering evaluation concluded Tefzel (fluorpolymer) tie wraps met environmental qualification requirements. Tefzel product performance was demonstrated by meeting the tensile strength requirements specified in the test report where it was subjected to normal life, accident and post accident conditions. Both the temperature and radiation capabilities exceed the maximum temperature and 60 years total integrated dose values, therefore based on plant-specific environmental qualification test results and plant engineering evaluation there are no aging effects requiring management for Tefzel cable tie wraps.
0532	Per plant procedure, nylon tie wraps may be used for applications outside the Radiologically Controlled Area (RCA) where they will not be exposed to environmental stresses such as extreme temperatures, ultraviolet radiation, or harsh chemicals. The temperature capability of nylon tie wraps exceeds the maximum temperature values for non-RCA areas, therefore there are no aging effects requiring management for nylon cable tie wraps.
0533	Components are the stainless steel missile deflectors for the spent fuel rack vents which are not within the scope of ISI-IWF. The identified AMPs will be used to manage the aging effects for the period of extended operation.
0534	The Thermo-Lag fire wraps at Columbia are abandoned in place. There are a few tray nodes where Thermo-lag is credited as electrical separation barrier, but not for Post-Fire Safe Shutdown. Siltemp tapes and Flame-Safe blankets are also used as electrical separation barriers.

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3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROL SYSTEMS

3.6.1 Introduction

Section 3.6 provides the results of the aging management reviews (AMRs) for those components and commodities identified in Section 2.5, Scoping and Screening Results – Electrical and Instrumentation and Control Systems, subject to AMR. The components and commodity groups subject to AMR are:

- Non-Environmentally Qualified Insulated Cables and Connections (Section 2.5.5.1)
- Metal-Enclosed Bus (Section 2.5.5.2)
- Switchyard Bus and Connections (Section 2.5.5.3)
- Transmission Conductors and Connections (Section 2.5.5.4)
- Uninsulated Ground Conductors and Connections (Section 2.5.5.5)
- High-Voltage Insulators (Section 2.5.5.6)

Table 3.6.1, Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801, provides the summary of the programs evaluated in NUREG-1801 that are applicable to component and commodity groups in this section. Text addressing summary items requiring further evaluation is provided in Section 3.6.2.2.

3.6.2 Results

The following table summarizes the results of the AMR for the components and commodity groups in the Electrical and Instrumentation and Control Systems area:

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

3.6.2.1 Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The materials from which specific components and commodity groups are fabricated, the environments to which they are exposed, the potential aging effects requiring management, and the aging management programs used to manage these aging effects are provided for each component and commodity group in the following sections.

3.6.2.1.1 Non-Environmentally Qualified Insulated Cables and Connections

The Non-Environmentally Qualified Insulated Cables and Connections commodity group is subdivided for AMR into the following categories:

- Non-Environmentally Qualified Insulated Cables and Connections
- Non-Environmentally Qualified Sensitive, High-Voltage, Low-Level Signal Instrument Cables and Connections
- Non-Environmentally Qualified Medium-Voltage Power Cables
- Cable Connections (Metallic Parts)
- Fuse Holders (Insulation)
- Fuse Holders (Metallic Clamp)

Materials

The materials of construction for the Non-Environmentally Qualified Insulated Cables and Connections are:

- Various Organic Polymers
- Various Metals
- Silicon Dioxide
- Copper Alloy (fuse holder metallic clamp)

Environments

The Non-Environmentally Qualified Insulated Cables and Connections are exposed to the following environments:

- Adverse localized environments
- Air – indoor uncontrolled
- Air - outdoor

Aging Effects Requiring Management

The aging effects requiring management for the Non-Environmentally Qualified Cables and Connections exposed to adverse localized environments are the following:

- Electrical Failure
- Localized Damage and Breakdown of Insulation
- Loosening of Bolted Connections

- Reduced Insulation Resistance

Aging Management Programs

The following aging management programs manage the aging effects for the Non-Environmentally Qualified Cables and Connections components:

- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection
- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

3.6.2.1.2 Metal-Enclosed Bus

The Metal-Enclosed Bus commodity group is subdivided for AMR into the following categories:

- Metal-Enclosed Bus, Non-Segregated (Bus and Connections)
- Metal Enclosed Bus, Non-Segregated (Enclosure Assemblies)
- Metal-Enclosed Bus, Non-Segregated (Insulation and Insulators)

Materials

The materials of construction for the Metal-Enclosed Bus components are:

- Aluminum
- Copper
- Silver Plate
- Elastomers
- Fiberglass
- Galvanized Steel
- Porcelain
- Steel
- Stainless Steel

- Various Organic Polymers (EPR and PVC tape)

Environments

The Metal-Enclosed Bus components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor

Aging Effects Requiring Management

The following aging effects require management for the Metal-Enclosed Bus components:

- Electrical Failure
- Hardening and Loss of Strength
- Loosening of Bolted Connections
- Loss of Material
- Reduced Insulation Resistance

Aging Management Programs

The following aging management programs manage the aging effects for the Metal-Enclosed Bus components:

- Metal-Enclosed Bus Program
- Structures Monitoring Program

3.6.2.1.3 Switchyard Bus and Connections

The Switchyard Bus and Connections commodity group is evaluated for aging management as follows:

Materials

The materials of construction for the Switchyard Bus and Connections are:

- Aluminum
- Galvanized steel

Environments

The Switchyard Bus and Connections are exposed to the following environment:

- Air - outdoor

Aging Effects Requiring Management

There are no aging effects identified as requiring management for the Switchyard Bus and Connections components (See Section 3.6.2.2.3).

Aging Management Programs

There are no aging effects identified as requiring management; therefore, no aging management programs are required for the Switchyard Bus and Connections components.

3.6.2.1.4 Transmission Conductors and Connections

The Transmission Conductors and Connections commodity group is evaluated for aging management as follows:

Materials

Transmission conductors are Type ACSR (aluminum conductor steel reinforced). The materials of construction for the Transmission Conductor and Connection components are:

- Aluminum
- Galvanized Steel
- Stainless Steel

Environments

The Transmission Conductor and Connection components are exposed to the following environment:

- Air - outdoor

Aging Effects Requiring Management

There are no aging effects identified as requiring management for the Transmission Conductor and Connection components (See Section 3.6.2.2.3).

Aging Management Programs

There are no aging effects identified as requiring management; therefore, no aging management programs are required for the Transmission Conductors and Connections components.

3.6.2.1.5 Uninsulated Ground Conductors and Connections

The Uninsulated Ground Conductors and Connections commodity group is evaluated for aging management as follows:

Materials

The material of construction for the Uninsulated Ground Conductors and Connections is:

- Copper

Environments

The Uninsulated Ground Conductors and Connections are exposed to the following environments:

- Air – outdoor
- Soil

Aging Effects Requiring Management

There are no aging effects identified as requiring management for the Uninsulated Ground Conductors and Connections components.

Aging Management Programs

There are no aging effects identified as requiring management; therefore, no aging management programs are required for the Uninsulated Ground Conductors and Connections components.

3.6.2.1.6 High-Voltage Insulators

The High-Voltage Insulators commodity group is evaluated for aging management as follows:

Materials

The materials of construction for the High-Voltage Insulators are:

- Cement
- Galvanized Metal

- Porcelain
- Stainless Steel

Environments

The High-Voltage Insulators are exposed to the following environment:

- Air - outdoor

Aging Effects Requiring Management

The following aging effect requires management for the High-Voltage Insulator components:

- Degradation of Insulator Quality

Aging Management Programs

The following aging management program manages the aging effects for the High-Voltage Insulator components:

- High-Voltage Porcelain Insulators Aging Management Program

3.6.2.2 Further Evaluation of Aging Management as Recommended by NUREG-1801

For the electrical and instrumentation and control (I&C) components, the items that require further evaluation are addressed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Analyses for environmental qualification of components with qualified lives of 40 years or greater are time-limited aging analyses, as defined in 10 CFR 54.3. The time-limited aging analyses are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this time-limited aging analysis is addressed in Section 4.4, Environmental Qualification of Electrical Equipment.

3.6.2.2.2 Degradation of Insulator Quality due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material due to Mechanical Wear

For Columbia, the deposition of contaminants on the high voltage insulators (in the 500-kV system) in the plant transformer yard has caused plant trips in the past. The root cause evaluations concluded that the specific meteorological conditions (i.e., the wind and temperature) at the time, along with the associated plume from the cooling towers (which slumped over the power block into the transformer yard), allowed a coating of ice to form, which also trapped liquid water containing minerals on the surface of the insulators, thereby allowing electrical tracking to occur. The corrective action was to implement a program to clean the insulators every two years. The event re-occurred on the 500-kV system. Additional testing was performed, which resulted in developing a coating system that has proven effective in mitigating the flashover when reapplied at least every 10 years.

Due to the operating experience with the 500-kV system, Columbia instituted a program to clean the high voltage insulators on the 115-kV system, identified for license renewal as the plant-specific High-Voltage Porcelain Insulators Aging Management Program, in order to manage the build-up of hard water residue from the cooling tower plume, and thereby mitigate potential degradation of the insulation function. This program allows for the option to either hand clean the in-scope high voltage insulators every two years or to coat the insulators every 10 years and inspect the coating for damage every two years between coatings. The operating experience indicates that this is only an issue with station post insulators. There are no station post insulators associated with the 230-kV system in the Columbia transformer yard, therefore the 230-kV system is excluded.

Loss of material due to mechanical wear is an aging effect for certain strain insulators if they are subject to significant movement. Such movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to sway from side to side. If this swinging motion occurs frequently enough, it could cause wear on the metallic contact points of the insulator string and between an insulator and the supporting hardware. Although this aging mechanism is possible, industry experience has shown that transmission conductors do not normally swing unless subjected to a substantial wind, and they stop swinging shortly after the wind subsides. Wind loading that can result in conductor sway is considered in the transmission system design. For insulators that are associated with switchyard bus, movement is precluded by the rigid design of the switchyard bus (i.e., the bus is of short length, is rigid itself, and is connected to rigid components). Review of operating experience has identified no concerns related to the occurrence of loss of material due to mechanical wear as a result of wind blowing on transmission conductors and the switchyard high voltage insulators. Therefore, loss of material due to mechanical wear is not an aging effect requiring management for the high voltage insulators at Columbia.

3.6.2.2.3 Loss of Material due to Wind Induced Abrasion and Fatigue, Loss of Conductor Strength due to Corrosion, and Increased Resistance of Connection due to Oxidation or Loss of Pre-Load

The switchyard bus which connects Back-up Transformer E-TR-B to circuit breaker E-CB-TRB and the bus between the 230 kV overhead line and circuit breaker A809 is within the scope of license renewal at Columbia. These are aluminum tube. The switchyard bus is connected to flexible connectors that do not normally vibrate and are supported by insulators and ultimately by structural components such as concrete footings and structural steel. With no connection to moving or vibrating equipment, vibration is therefore not an applicable aging mechanism. The aluminum bus will form a very thin surface layer of oxidation, but the tube itself does not oxidize and the conductor properties are not degraded by a thin surface oxidation layer. The Columbia applications incorporate the use of galvanized or stainless steel "Belleville" washers on bolted electrical connections using galvanized or stainless steel bolts, nuts, and washers to compensate for temperature changes and to maintain the proper tightness. The bolted connections are exposed to the ambient service conditions in the switchyard bus locations at Columbia (in the plant transformer yard and in the Ashe substation), and do not experience any aging effects that require management.

From EPRI TR-104213 ("Bolted Joint Maintenance & Applications Guide"), Section 15.7.5.3, ANSI B18.21.1 ("Lock Washers") has not changed since 1972. Prior to that year, it was designated ASA B27.1 (1965). The specification was changed in 1972 regarding embrittlement. Prior to 1972, there was no statement made to prevent possible hydrogen embrittlement if the washers were plated. Because construction of the Columbia transformer yard post-dates 1972, there is strong assurance that the washers used at Columbia are not subject to hydrogen embrittlement.

Wind-induced abrasion and fatigue are not aging effects applicable to the in-scope transmission conductors. Industry experience has shown that transmission conductors do not normally swing unless subjected to substantial winds, and they stop swinging after a short period once the wind subsides. Because the transmission conductors are not normally moving, the loss of material due to wind-induced abrasion and fatigue is not an aging effect requiring management.

Loss of conductor strength due to corrosion of the transmission conductor is not identified as an aging effect due to ample design margin and a minimal corrosion process at the rural location of Columbia. Connection resistance is not identified as a stressor based on use of good bolting practices and review of site operating experience.

EPRI Report 1013475, the License Renewal Electrical Handbook, concludes that the most prevalent aging mechanism contributing to loss of conductor strength of ACSR (aluminum conductor steel reinforced) transmission conductors is corrosion. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality, which involves suspended particles in the air, sulfur dioxide (SO_2) concentration, rain, fog chemistry, and other weather conditions. Corrosion of ACSR conductors is a very slow process that is even slower in rural areas with less air pollution. Columbia is located in a rural area in east-central Washington state, where airborne particle concentrations are low.

Tests performed by Ontario Hydroelectric showed a 30 percent composite loss of conductor strength for an 80 year-old sample of an ACSR conductor (due to corrosion). The Ontario Hydroelectric Test Report is available from the Institute of Electrical and Electronics Engineers (IEEE). The report is documented in two parts in the IEEE Transactions on Power Delivery, Volume 7, Number 2, April 1992©. The papers present the test methods and results of both field and laboratory tests on samples of ACSR (aluminum conductor steel reinforced) conductors from Ontario Hydroelectric's older transmission lines. The field testing involved detection of steel core galvanizing loss via the use of an overhead line conductor corrosion detector. Laboratory tests (using a dynamometer) were performed for fatigue, tensile strength, torsional ductility, and electrical performance. The report also addressed metallurgical data and analysis of potential environmental contributors.

With respect to the Ontario Hydroelectric study, the National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength and that consideration for ice, wind, and temperature be included in the design. The discussion in EPRI 1013475 demonstrates that with a 30 percent loss of conductor strength, there is still margin between the NESC requirements and the actual conductor strength. Because the Columbia transmission conductor design and installation meets the NESC requirements, the Ontario Hydroelectric study bounds the Columbia configuration. The specific comparisons are addressed below.

The transmission conductors within the scope of license renewal are "Drake" ACSR 795 MCM (thousand circular mils) with a 26/7 stranding (for the 230-kV system). The Ontario Hydro testing included ACSR with the same stranding configuration as the Columbia transmission conductors. The Columbia transmission conductors have an ultimate strength of 31,200 pounds for the "Drake" configuration. The "Drake" conductor has a maximum design working tension of 8,000 pounds. Because the Ontario Hydro study demonstrated a 30 percent loss of ultimate strength in an 80 year-old conductor, the Columbia transmission conductors are shown to demonstrate the following:

Normal margin (ultimate versus maximum design tension):

"Drake" - (31,200 – 8,000) / (31,200) = 0.74 x 100 = 74 percent

Aged margin (assuming a 30 percent loss of ultimate strength):

"Drake" - [(0.7)*(31,200) – 8,000] / [(31,200)*(0.7)] = 0.63 x 100 = 63 percent

This demonstrates that (using the Ontario Hydroelectric test data) the Columbia transmission conductors will have greater than 63 percent ultimate strength margin remaining after 80 years.

Therefore, based on the expected low corrosion rates due to plant location and the margins included in the design, corrosion of the transmission conductors is not an aging effect requiring management for the period of extended operation.

Increased connection resistance is not identified as an aging effect requiring management. Bolted connections associated with the transmission conductors employ the use of good bolting practices consistent with the recommendations of EPRI 1003471, "Electrical Connector Application Guidelines." The preferred hardware for the connections is stainless steel. The Columbia applications incorporate the use of stainless steel "Belleville" washers on bolted electrical connections using stainless steel bolts, nuts, and washers to compensate for temperature changes and to maintain the proper tightness. Aluminum hardware is also used for aluminum to aluminum bus connections, but stainless steel is preferred. Use of aluminum fasteners with aluminum bus minimizes any differences in thermal expansion that could lead to loss of pre-load. In addition, design installation drawings provide guidance on bolted joints (copper to aluminum, aluminum to aluminum, and aluminum to copper). Design documents also require the use of an electrical joint compound, to be used in accordance with the manufacturer's recommendations. These methods of assembly (particularly the use of the "Belleville" washers) are consistent with EPRI 1003471. The review of site operating experience revealed no bolted connection failures associated with transmission conductors.

3.6.2.2.4 Quality Assurance for Aging Management of Non-safety Related Components

Quality Assurance provisions applicable to license renewal are discussed in Appendix B, Section B.1.3.

3.6.2.3 Time-Limited Aging Analyses

The time-limited aging analyses identified below are associated with the electrical and I&C components. The section of the application that contains the time-limited aging analysis review results is indicated in parentheses.

- Analyses for Environmental Qualification of components with a qualified life of 40 years or greater (Section 4.4, Environmental Qualification of Electrical Equipment)

3.6.3 Conclusions

The electrical and I&C components and commodities subject to aging management review have been identified in accordance with 10 CFR 54.21. The aging management programs selected to manage the effects of aging for the electrical components and commodities are identified in the following tables and Section 3.6.2.1. A description of the aging management programs is provided in Appendix B of this application, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the electrical and I&C components and commodities will be managed so that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-01	Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements	Degradation due to various aging mechanisms	Environmental Qualification of Electrical Components	Yes, TLAA	This TLAA is evaluated in Section 4.4. Refer to Section 3.6.2.2.1 for further information.
3.6.1-02	Electrical cables, connections, and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	No	Consistent with NUREG-1801.
3.6.1-03	Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (IR)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Used in Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements	No	Consistent with NUREG-1801.
3.6.1-04	Conductor insulation for inaccessible medium voltage (2-kV to 35-kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	No	Consistent with NUREG-1801.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-05	Connector contacts for electrical connectors exposed to borated water leakage	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion	No	Not applicable for Columbia. Columbia is a BWR and does not use boric acid in any systems. The Standby Liquid Control System uses a sodium pentaborate solution (a mixture of boric acid and borax) that is not aggressive to metals.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-06	Fuse Holders (Not Part of a Larger Assembly): Fuse Holders – metallic clamp	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable for Columbia. The aging effects detailed in NUREG-1801 are not applicable for this item. None of the fuse holders that are within the scope of license renewal contain fuses that are frequently manipulated. Inspection of a sample of the passive fuse boxes found the condition to be clean and dry, with no signs of contamination or corrosion or moisture intrusion. Similarly, ohmic heating, thermal cycling, electrical transients, and vibration do not apply to the passive fuse boxes at Columbia because the fuses are not heavily loaded (in their installed applications) and do not experience frequent electrical and thermal cycling. Power fuses are bolted to maintain electrical contact. Vibration is an induced aging mechanism, and is not applicable because the electrical boxes are securely mounted on walls.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-07	Metal-enclosed bus – Bus/connections	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal-Enclosed Bus	No	Consistent with NUREG-1801, with exceptions. The Metal-Enclosed Bus Program is credited.
3.6.1-08	Metal-enclosed bus – Insulation/insulators	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal-Enclosed Bus	No	Consistent with NUREG-1801, with exceptions. The Metal-Enclosed Bus Program is credited..
3.6.1-09	Metal-enclosed bus – Enclosure assemblies	Loss of material due to general corrosion	Structures Monitoring Program	No	Consistent with NUREG-1801.
3.6.1-10	Metal-enclosed bus – Enclosure Assemblies	Hardening and loss of strength due to elastomer degradation	Structures Monitoring Program	No	Consistent with NUREG-1801 item for material, environment, and aging effect, but a different aging management program is credited. The Metal-Enclosed Bus Program is credited.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-11	High-Voltage Insulators	Degradation of insulation quality due to the presence of any salt deposits and surface contamination; Loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	Yes, plant-specific	The High-Voltage Porcelain Insulators Aging Management Program is credited. Loss of material due to wear is not an applicable aging effect for the in-scope high-voltage insulators at Columbia. Refer to Section 3.6.2.2.2 for further information.
3.6.1-12	Transmission conductors and connections; Switchyard bus and connections	Loss of material due to wind-induced abrasion and fatigue; Loss of conductor strength due to corrosion, increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes, plant-specific	No aging effects are identified as requiring aging management. Refer to Section 3.6.2.2.3 for further information.

Table 3.6.1 Summary of Aging Management Programs for Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-13	Cable connections – Metallic parts	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Consistent with NUREG-1801, with exceptions. See Appendix B Section B.2.21.
3.6.1-14	Fuse Holders (Not Part of a Larger Assembly) – Insulation Material	None	None	N/A – No AEM or AMP	Consistent with NUREG-1801.

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
1	Cable Connections (Metallic Parts)	Conduct Electricity	Various Metals (used for electrical contact)	Air – indoor uncontrolled and Air - outdoor	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection	VI.A-1	3.6.1-13	B

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
2	Non-Environmentally Qualified Insulated Cables and Connections	Conduct Electricity	Various Organic Polymers Silicon Dioxide	Adverse localized environment caused by heat, radiation, or moisture in the presence of oxygen	Embrittlement, cracking, melting, *discoloration*, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical *failure/* degradation of organics (thermal/ thermoxidative) radiolysis and photolysis (UV-sensitive materials only) of organics; radiation-induced oxidation, and *moisture* intrusion	Electrical Cables and Connections Not *Subject to* 10 CFR 50.49 EQ Requirements Program	VI.A-2	3.6.1-02	A

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
3	Non-Environmentally Qualified Sensitive, High-Voltage, Low-Level Signal Instrument Cables and Connections	Conduct Electricity	Various Organic Polymers	Adverse localized environment caused by heat, radiation, or moisture in the presence of oxygen	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation of organics (thermal/ thermoxidative) radiolysis and photolysis (UV-sensitive materials only) of organics; radiation-induced oxidation, and moisture intrusion	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program	VI.A-3	3.6.1-03	A

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
4	Non-Environmentally Qualified Medium-Voltage Power Cables	Conduct Electricity	Various Organic Polymers	Adverse localized environment caused by exposure to moisture and voltage	Localized damage and breakdown of insulation leading to electrical failure / moisture intrusion, water trees	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program	VI.A-4	3.6.1-04	A

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
5	Fuse Holders: Insulation	Conduct Electricity	Various Organic Polymers	Adverse localized environment caused by heat, radiation, or moisture in the presence of oxygen or > 60-year service limiting temperature	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation (thermal/ thermoxidative) of organics/ thermoplastics; radiation-induced oxidation, moisture intrusion, and ohmic heating	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program	VI.A-6	3.6.1-02	A
6	Fuse Holders: Insulation	Conduct Electricity	Various Organic Polymers	Air – indoor uncontrolled	None Identified	None Required	VI.A-7	3.6.1-14	A

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
7	Fuse Holders: Metallic Clamp	Conduct Electricity	Copper Alloy	Air - Indoor uncontrolled	None Identified	None Required	VI.A-8	3.6.1-06	I 0603 0607
8	High-Voltage Insulators	Insulation (and support)	Porcelain, Galvanized Metal, Stainless Steel, Cement	Air - Outdoor	Degradation of insulator quality / presence of any salt deposits or surface contamination	High-Voltage Porcelain Insulators Aging Management Program	VI.A-9	3.6.1-11	E 0608
9	High-Voltage Insulators	Insulation (and support)	Porcelain, Galvanized Metal, Stainless Steel, Cement	Air - Outdoor	None Identified	None Required	VI.A-10	3.6.1-11	I 0601
10	Metal-Enclosed Bus (bus and connections) (non-segregated)	Conduct Electricity	Aluminum / Silver Plated Aluminum, Copper / Silver Plated Copper, Stainless Steel, Steel	Air - Indoor uncontrolled and Air - Outdoor	Loosening of bolted connections / thermal cycling and ohmic heating	Metal-Enclosed Bus Program	VI.A-11	3.6.1-07	B

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
11	Metal-Enclosed Bus (Enclosure Assemblies) (non-segregated)	Support	Elastomers	Air - Indoor uncontrolled and Air - Outdoor	Hardening and loss of strength / elastomer degradation	Metal-Enclosed Bus Program	VI.A-12	3.6.1-10	E 0605
12	Metal-Enclosed Bus (enclosure assemblies) (non-segregated)	Support	Aluminum, Steel, Galvanized Steel	Air - Indoor uncontrolled and Air - Outdoor	Loss of material / general corrosion	Structures Monitoring Program	VI.A-13	3.6.1-09	A 0605 0606

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups

Row No.	Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
13	Metal-Enclosed Bus (insulation and insulators) (non-segregated)	Insulation	Porcelain, Fiberglass, Various Organic Polymers (EPR and PVC tape)	Air - Indoor uncontrolled and Air - Outdoor	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ thermal/ thermoxidative degradation of organics/ thermoplastics; radiation-induced oxidation; moisture/ debris intrusion, and ohmic heating	Metal-Enclosed Bus Program	VI.A-14	3.6.1-08	B
14	Switchyard Bus and Connections	Conduct Electricity	Aluminum, Galvanized Steel	Air - Outdoor	None Identified	None Required	VI.A-15	3.6.1-12	I 0602

Table 3.6.2-1 Aging Management Review Results - Electrical Component Commodity Groups									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
15	Transmission Conductors and Connections	Conduct Electricity	Aluminum, Galvanized Steel, Stainless Steel	Air - Outdoor	None Identified	None Required	VI.A-16	3.6.1-12	I 0604
16	Uninsulated Ground Conductors and Connections	Conduct Electricity	Copper	Air – Outdoor and Soil	None Identified	None Required	N/A	N/A	J 0609
17	Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Various	Various organic polymers and metallic materials	Adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage	Various degradations / various mechanisms	TLAA	VI.B-1	3.6.1-01	A

Generic Notes:	
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant-Specific Notes:	
0601	Loss of material due to wear is not an applicable aging effect for the in-scope high-voltage insulators at Columbia - see Section 3.6.2.2.2 for evaluation.
0602	For the switchyard bus and connections, no aging effects are identified that require aging management - refer to Section 3.6.2.2.3 for evaluation.
0603	A review of the Columbia fuse list and other engineering documents showed that there are no in-scope passive fuses that are pulled on a routine basis such that deformation (fatigue) would cause loosening of the fuse holder. The in-scope fuse holders at Columbia are located in metallic electrical boxes (terminal boxes) which have covers to protect the interior of the box from the ambient environment. The boxes are not exposed to weather conditions (they are located indoors); they are not exposed to chemical contamination or spills; they are not exposed to mechanical stress inside the box; and, due to the Columbia location in rural central Washington, they are not located in an evironment with industrial pollution or salt deposition. Therefore, chemical contamination, corrosion, and oxidation are not applicable aging mechanisms for the fuse holders within the license renewal scope at Columbia. With respect to electrical transients and ohmic heating, these fuses are not heavily loaded and do not experience frequent electrical and thermal cycling. With respect to vibration, it is an induced aging mechanism, and the fuse boxes are securely mounted on walls, so vibration itself is not an applicable stressor.
0604	The transmission conductors within the license renewal scope are those that connect start-up transformer E-TR-S to circuit breaker A 809 in the Ashe substation switchyard. This circuit breaker constitutes part of the station blackout license renewal boundary. This segment of transmission conductor does not exhibit significant aging mechanisms or effects. An aging management program is not required for the segment of transmission conductor that is within the scope of license renewal. See Section 3.6.2.2.3 for details.
0605	The inspection of the metal-enclosed bus enclosure assembly elastomers (joints, seals, gaskets) will be performed as part of the Metal-Enclosed Bus Program. The elastomers will be inspected when the covers of the various bus enclosure sections are removed. The Structures Monitoring Program will address the metallic portion of the enclosure assembly and the external structural supports for the various bus assemblies (along with the building penetrations and seals where the bus ducts enter the Reactor Building).
0606	In addition to steel and galvanized steel, Columbia uses aluminum enclosures (a material not mentioned in NUREG-1801, Item VI.A-13). Note A is used, because the Structures Monitoring Program includes consideration of aluminum and is consistent with NUREG-1801.
0607	Inspection of a sample of the passive fuse boxes within the scope of license renewal (performed in September 2007) showed that conditions are clean and dry, with no corrosion or moisture intrusion found.

Plant-Specific Notes:	
0608	See Section 3.6.2.2.2 for a description of the surface contamination item affecting the high-voltage insulators in the Columbia transformer yard.
0609	The uninsulated ground conductors and connections are included in the license renewal scope because they are required for fire protection (from lightning-induced fires) on certain structures and for facilitating the operation of ground fault detection devices in the event of ground fault or insulation failure on any electrical load or current (see Section 2.5.5.5). There are no aging effects requiring management for the metallic components of the uninsulated ground conductors and connections.

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4.0 TIME-LIMITED AGING ANALYSES

10 CFR 54 governs the issuance of renewed operating licenses for nuclear power plants and includes requirements for the performance of an integrated plant assessment (IPA) and the review of time-limited aging analyses. The results of the IPA and time-limited aging analysis (TLAA) evaluations form the technical bases upon which the Columbia Generating Station (Columbia) license renewal application is built.

This section provides the results of reviews of potential TLAAs and exemptions specific to Columbia for license renewal and documents evaluations of each identified item for the period of extended operation. This section dispositions each identified TLAA in accordance with 10 CFR 54.21(c).

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4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

Time-limited aging analyses are defined in 10 CFR 54.3 as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
(2) Consider the effects of aging;
(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
(4) Were determined to be relevant by the licensee in making a safety determination;
(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and
(6) Are contained or incorporated by reference in the CLB.

4.1.1 Time-Limited Aging Analyses Identification Process

The major emphasis in the License Renewal Rule (10 CFR 54) is that the CLB must be maintained during the period of extended operation. Time-limited aging analyses that are contained or incorporated by reference in the CLB at Columbia are identified, as required by 10 CFR 54. The CLB documentation that was searched to identify potential TLAAs includes the following:

- Final Safety Analysis Report (FSAR)
- Fire Protection Evaluation
- Quality Assurance Program
- In-Service Inspection Program
- Docketed Licensing Correspondence
- Operating License (including Technical Specifications)
- Code Exemptions and Relief Requests
- Design Calculations and Design Reports

Industry documents that list generic time-limited aging analyses were reviewed to provide additional assurance of the completeness of the plant-specific list. These documents include NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1, NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 6, Boiling Water Reactor Vessel and Internals Project

(BWRVIP) reports and recent license renewal applications for boiling water reactor designs.

Each potential TLAA identified is reviewed to determine if it meets the definition of a TLAA in accordance with 10 CFR 54.3. Columbia analyses and calculations that meet the TLAA definition are evaluated in accordance with the options provided in 10 CFR 54.21(c)(1).

4.1.2 Evaluation of Time-Limited Aging Analyses

As required by 10 CFR 54.21(c)(1), an evaluation of Columbia-specific TLAAs must be performed to demonstrate that:

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The results of these evaluations are summarized in Table 4.1-1 and Table 4.1-2 and discussed in Sections 4.2 through 4.7.

4.1.3 Identification of Exemptions

Pursuant to 10 CFR 54.21(c)(2), an applicant for license renewal must provide: (1) a listing of plant-specific exemptions granted pursuant to 10 CFR 50.12 that are in effect and based on a TLAA, and (2) an evaluation of these exemptions to justify their continuation for the period of extended operation. Columbia current licensing basis documentation, identified in Section 4.1.1, was reviewed for exemptions.

As a result of the review, there were no exemptions identified that are based on a TLAA.

Table 4.1-1
Time-Limited Aging Analyses

Results of TLAA Evaluation by Category	10 CFR 54.21(c)(1) Paragraph	LRA Section
Reactor Vessel Neutron Embrittlement		4.2
Neutron Fluence	Not a TLAA	4.2.1
Upper Shelf Energy (USE)	(ii)	4.2.2
Adjusted Reference Temperature (ART)	(ii)	4.2.3
Pressure-Temperature (P-T) Limits	(iii)	4.2.4
Reactor Vessel Circumferential Weld Examination Relief	(ii)	4.2.5
Reactor Vessel Axial Weld Failure Probability	(ii)	4.2.6
Metal Fatigue		4.3
Reactor Pressure Vessel Fatigue Analyses	(iii)	4.3.1
Reactor Vessel Internals Fatigue Analyses	(iii)	4.3.2
Reactor Coolant Pressure Boundary Piping and Component Fatigue Analyses	(iii)	4.3.3
Non-Class 1 Component Fatigue Analyses	(i)	4.3.4
Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping	(iii)	4.3.5
Environmental Qualification of Electrical Equipment	(iii)	4.4
Concrete Containment Tendon Prestress	Not a TLAA	4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses		4.6
ASME Class MC Components	(i)	4.6.1
Downcomers	(i)	4.6.2
Safety Relief Valve Discharge Piping	(i)	4.6.3
Diaphragm Floor Seal	(i)	4.6.4
ECCS Suction Strainers	(i)	4.6.5
Other Plant-Specific Time-Limited Aging Analyses		4.7
Reactor Vessel Shell Indications	(iii)	4.7.1
Sacrificial Shield Wall	(ii)	4.7.2
Main Steam Line Flow Restrictor Erosion Analysis	(ii)	4.7.3

Table 4.1-2
Review of Generic TLAAs Listed in Tables 4.1-2 and 4.1-3 of NUREG-1800

NUREG-1800 Generic TLAAs Example	Applicability to Columbia	LRA Section
NUREG-1800, Table 4.1-2		
Reactor Vessel Neutron Embrittlement	Yes	4.2
Concrete Containment Tendon Prestress	No – Columbia does not have containment tendons	4.5
Metal Fatigue	Yes	4.3
Environmental Qualification of Electrical Equipment	Yes	4.4
Metal Corrosion Allowance	No – No explicit 40-year basis applies.	--
Inservice Flaw Growth Analyses that Demonstrate Structure Stability for 40 Years	Yes	4.7.1
Inservice Local Metal Containment Corrosion Analyses	No – No explicit 40-year basis applies.	--
High-Energy Line-Break Postulation Based on Fatigue Cumulative Usage Factor	Yes	4.3.3
NUREG-1800, Table 4.1-3		
Intergranular Separation in the Heat-Affected Zone (HAZ) of Reactor Vessel Low-Alloy Steel Under Austenitic Stainless Steel Cladding	No – No HAZ analysis was identified within the CLB.	--
Low-Temperature Overpressure Protection (LTOP) Analyses	No – No LTOP analysis was identified within the CLB.	--
Fatigue Analysis for the Main Steam Supply Lines to the Turbine-Driven Auxiliary Feedwater Pumps	No – Columbia is a BWR and does not have an Auxiliary Feedwater System.	--
Fatigue Analysis of the Reactor Coolant Pump Flywheel	No –Recirculation System pumps do not have flywheels.	--
Fatigue Analysis of Polar Crane	No – No explicit 40-year basis applies.	--

Table 4.1-2 (continued)
Review of Generic TLAAs Listed in Tables 4.1-2 and 4.1-3 of NUREG-1800

NUREG-1800 Generic TLAAs Example	Applicability to Columbia	LRA Section
NUREG-1800, Table 4.1-3 (cont.)		
Flow-Induced Vibration Endurance Limit for the Reactor Vessel Internals	No – No analyses were identified within the CLB for the reactor vessel internals related to this topic.	--
Transient Cycle Count Assumptions for the Reactor Vessel Internals	Yes	4.3.2
Ductility Reduction of Fracture Toughness for the Reactor Vessel Internals	No – No analyses were identified within the CLB for the reactor vessel internals related to this topic.	--
Leak Before Break	No – Columbia does not credit Leak Before Break.	--
Fatigue Analysis for the Containment Liner Plate	No – Columbia does not have a liner plate, but the metal shell is analyzed for fatigue.	4.6.1
Containment Penetration Pressurization Cycles	Yes	4.6.1
Reactor Vessel Circumferential Weld Inspection Relief (BWR)	Yes	4.2.5

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4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT

Neutron embrittlement is the term used to describe changes in mechanical properties of reactor vessel materials that result from exposure to fast neutron flux (E>1.0 MeV) within the beltline region. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to crack propagation decreases. Fracture toughness is also dependent on temperature. The reference temperature for nil-ductility transition (RT_{NDT}) is the temperature above which the material behaves in a ductile manner and below which the material behaves in a brittle manner. As fluence increases, RT_{NDT} increases. This means higher temperatures are required for the material to continue to act in a ductile manner.

The regulations governing reactor vessel integrity are in 10 CFR Part 50. Section 50.60 requires that all light-water reactors meet the fracture toughness, pressure-temperature limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in Appendices G and H of 10 CFR 50.

The analyses associated with evaluation of the effect of neutron embrittlement on the Columbia reactor pressure vessel for 40 years are TLAAs. Neutron fluence, upper shelf energy (USE), adjusted reference temperature (ART), and vessel pressure-temperature (P-T) limits are time dependent parameters that must be investigated with respect to fracture toughness (embrittlement) of reactor vessel materials.

The following sections address fluence, USE, ART, P-T limits, circumferential welds, and axial welds for the reactor pressure vessel (RPV) beltline materials for the period of extended operation. This discussion uses the latest data, as submitted to the NRC on June 9, 2004 (Reference 4.8-1) and approved by the NRC in license amendment number 193 on May 12, 2005 (Reference 4.8-2). The latest data supersedes the information currently in the NRC's Reactor Vessel Integrity Database (RVID2).

4.2.1 Neutron Fluence

EFPY Projection

To evaluate the effects of radiation on RPV material embrittlement, the results of analyses were projected to determine neutron fluence out to 54 effective full power years (EFPY). Using actual reactor core power histories to-date and conservative estimates of future core designs, extended operation to 60 years will be bounded by 54 EFPY. (Reaching 54 EFPY would require a plant capacity factor in excess of 95 percent from now until the end of the period of extended operation.)

Fluence Projection

Fluence values at 51.6 EFPY of reactor operation (analyzed by General Electric (GE) in Reference 4.8-3) are addressed in FSAR Section 4.3.2.8 and FSAR Table 4.3-1. These fluence analyses are based on the original licensed thermal power of 3323 megawatt-thermal (MWt) through fuel cycle 10, and the currently licensed thermal power uprated to 3486 MWt from cycle 11 through the end of operation. These fluence analyses are based on the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation." NEDC-32983P was approved by NRC letter (Reference 4.8-4) with acceptability based on the fact that the methodology followed the guidance in Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

Subsequently, GE incorporated the fluence analyses into a personal computer worksheet to allow production of fluence estimates at other EFPY. For purposes of license renewal, the reported fluence was linearly extrapolated from 33.1 EFPY (the original 40-year end of life estimate) through 51.6 EFPY to 54 EFPY. Those projections match the fluence values obtained from the automated worksheet for 54 EFPY.

A summary of the highest estimated values of fluence for the RPV beltline shells and welds is shown in Table 4.2-1. Fluence is calculated at the inner surface (0T) of the vessel and at ¼ thickness (1/4T) depth into the vessel.

Beltline Evaluation

NUREG-1801 indicates that ferritic materials for RPV beltline shells, welds, and assembly components are to be evaluated for neutron irradiation embrittlement if high energy neutron fluence is greater than a threshold value of 1E+17 n/cm^2 (E >1 MeV) at the end of the license renewal term. The only RPV assembly items, other than the shells and welds in Table 4.2-1, that would experience neutron fluence greater than 1E+17 n/cm^2 during the period of extended operation are instrumentation nozzle N12 and residual heat removal/low-pressure coolant injection (RHR/LPCI) nozzle N6.

Instrumentation nozzle N12 has a thickness less than 2.5 inches and therefore requires no fracture toughness evaluation per ASME Code Appendix G, Section G2223, and thus is not evaluated.

Nozzle N6 is evaluated for ART in Section 4.2.3 and Table 4.2-5 below. As shown in Table 4.2-5, the ART for these nozzles is only 22.2 °F, versus 53.8 °F for the highest weld and 73.6 °F for the highest plate. Consequently, nozzle N6 is not the limiting material for the vessel. However, as nozzle N6 was evaluated for ART it meets the definition of a beltline component per 10 CFR 50, Appendix G.

As such, the beltline definition for the period of extended operation includes the lower shell, lower-intermediate shell, associated vertical (longitudinal) welds, the girth (circumferential) weld that connects the lower and lower-intermediate shells, and nozzle N6.

Disposition: Neutron fluence is not a TLAA. It is a time-limited assumption used in various neutron embrittlement TLAAs.

Table 4.2-1
RPV Beltline Fluence Values at 54 EFPY

PLATES:	Identification (I.D.) No.	0T fluence (n/cm^2)	1/4T fluence (n/cm^2)
Lower Shell	Mk 21-1-1, Mk 21-1-2, Mk 21-1-3, Mk 21-1-4	4.78E+17	2.71E+17
Lower-Intermediate Shell	Mk 22-1-1, Mk 22-1-2, Mk 22-1-3, Mk 22-1-4	1.17E+18	8.10E+17
NOZZLES:			
N6 (RHR / LPCI) (3 nozzles)	Mk 64-1	6.49E+17	4.48E+17
WELDS:			
Lower Vertical (Axial / Longitudinal)	BA, BB, BC, BD	4.78E+17	2.71E+17
Lower-Intermediate Vertical (Axial / Longitudinal)	BE, BF, BG, BH	1.17E+18	8.10E+17
Lower to Lower-Intermediate Girth (Circumferential)	AB	4.78E+17	3.3E+17

4.2.2 Upper Shelf Energy Evaluation

10 CFR 50 Appendix G requires the USE of the RPV beltline materials to remain above 50 ft-lb at all times during plant operation, including the effects of neutron radiation. If USE cannot be shown to remain above this limit, then an equivalent margin analysis (EMA) must be performed to show that the margins of safety against fracture are equivalent to those required by Appendix G of Section XI of the ASME Code.

The USE calculation of record for the existing licensed period (33.1 EFPY) is Appendix F of GE NEDO-33144 (Reference 4.8-5). The initial (unirraditated) USE is not known for all the Columbia vessel plates and welds. For those plates and welds for which the initial USE is known, USE was projected using Regulatory Guide 1.99, Revision 2 methods. For the vessel plates and welds for which the initial USE is not known, USE EMAs were performed using the Boiling Water Reactor Owners Group EMA methodology. Results from the testing and analysis of surveillance materials were used in the EMA analyses.

The values of USE projected to 54 EFPY are listed in Table 4.2-2. All of the projected USE values from Table 4.2-2 remain above 50 ft-lbs through the end of the period of extended operation (54 EFPY).

The projected EMAs are listed in Table 4.2-3 and Table 4.2-4. The projected EMAs in Table 4.2-3, and Table 4.2-4 used the projected 54 EFPY fluence listed in Table 4.2-1, and the curves provided in RG 1.99 Figure 2. The predicted values were compared to the minimum 54 EFPY USE limits in BWRVIP-74-A.

For the vessel beltline plates, the maximum decrease in USE was found to be 13.2 percent (see Table 4.2-3). This is less than the assumed decrease of 23.5 percent in the beltline plate equivalent margin analysis. Therefore, the maximum predicted decreases in USE for 54 EFPY for the beltline plates are bounded by the generic 54 EFPY equivalent margin analysis documented in BWRVIP-74-A. The projected USE for the vessel beltline plates is acceptable for the period of extended operation.

For the welds associated with the vessel beltline plates, the maximum decrease in USE was found to be 21.6 percent (see Table 4.2-4). This is less than the assumed decrease of 39 percent in the equivalent margin analysis. Therefore, the maximum predicted decreases in USE for the welds in the vessel beltline region are bounded by the generic 54 EFPY equivalent margin analysis documented in BWRVIP-74-A. The projected USE for the beltline welds is acceptable for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(ii) – Reactor vessel upper shelf energy TLAAs have been projected to the end of the period of extended operation.

Table 4.2-2
USE Projections for 54 EFPY

Sub-Component(1)	I.D. No.	Heat (Single/Tandem wire)	% Cu	Initial USE	¼T Fluence n/cm^2	Drop in USE	¼T USE (ft-lb)
PLATES:							
Lower-Intermediate Shell (Course #2)	Mk 22-1-1	B5301-1	0.13	98	8.10E+17	12.1%	86.1
WELDS:							
Lower Vertical (Axial/Longitudinal)	BA-BD	3P4966 (S)	0.025	98	2.71E+17	7.0%	91.1
		3P4966 (T)	0.025	98	2.71E+17	7.0%	91.1
Lower-Intermediate Vertical (Axial/Longitudinal)	BE-BH	3P4966 (S)	0.025	98	8.10E+17	9.1%	89.1
		3P4966 (T)	0.025	98	8.10E+17	9.1%	89.1
Lower to Lower-Intermediate Girth (Circumferential)	AB	5P6756 (S)	0.080	91	3.30E+17	9.8%	82.1
		5P6756 (T)	0.080	97	3.30E+17	9.8%	87.5
	AB	3P4955 (S)	0.027	90	3.30E+17	7.4%	83.3
		3P4955 (T)	0.027	95	3.30E+17	7.4%	87.9

(1) The sub-components not on this table have no projection due to the initial USE being unknown. See Table 4.2-3 and Table 4.2-4 for the equivalent margin analyses for the limiting plate and weld.

Table 4.2-3
RPV Beltline Plate USE Equivalent Margin Analysis for 54 EFPY

Surveillance Plate USE (Heat: B5301-1)		
% Cu	=	0.13
Unirradiated USE	=	98.0 ft-lb
1st Capsule Measured USE	=	99.6 ft-lb
1st Capsule Fluence	=	1.55E+17 n/cm^2
1st Capsule Measured Decrease	=	-1.6 %
1st Capsule RG 1.99 Predicted Decrease	=	8.0 %
Limiting Beltline Plate USE (Heat: C1337-1 and C1337-2)		
% Cu	=	0.15
54 EFPY ¼T Fluence	=	8.10E+17 n/cm^2
RG 1.99 Predicted Decrease	=	13.2 %
Adjusted Decrease	=	N/A
13.2 % ≤		23.5 % (bounding value from SER for BWRVIP-74-A)
Therefore, the vessel plates are bounded by Equivalent Margin Analysis in BWRVIP-74-A.		

Table 4.2-4
RPV Beltline Weld USE Equivalent Margin Analysis for 54 EFPY

Surveillance Weld USE (Heat 3P4966):		
% Cu	=	0.03
Unirradiated USE	=	98.0 ft-lb
1st Capsule Measured USE	=	108.0 ft-lb
1st Capsule Fluence	=	1.55E+17 n/cm^2
1st Capsule Measured Decrease	=	-10.2 %
1st Capsule RG 1.99 Predicted Decrease	=	6.0 %
ISP Surveillance Weld USE (Heat 5P6756):		
% Cu	=	0.06
Unirradiated USE	=	104.4 ft-lb
River Bend 183° Capsule Measured USE	=	84.4 ft-lb
River Bend 183° Capsule Fluence	=	1.16E+18 n/cm^2
SSP Capsule F Measured USE	=	79.3 ft-lb
SSP Capsule F Fluence	=	1.94E+18 n/cm^2
SSP Capsule H Measured USE	=	84.6 ft-lb
SSP Capsule H Fluence	=	1.36E+18 n/cm^2
River Bend 183° Capsule Measured Decrease	=	19.2 %
River Bend 183° Capsule RG 1.99 Predicted Decrease	=	12.5 %
SSP Capsule F Measured Decrease	=	24.0 %
SSP Capsule F RG 1.99 Predicted Decrease	=	14.0 %
SSP Capsule H Measured Decrease	=	19.0 %
SSP Capsule H RG 1.99 Predicted Decrease	=	13.0 %
Limiting Beltline Weld USE (Heat 624039/D205A27A):		
% Cu	=	0.10
54 EFPY ¼T Fluence	=	8.10E+17 n/cm^2
RG 1.99 Predicted Decrease	=	13.2 %
Adjusted Decrease	=	21.6 % [(1)]
21.6 % (54 EFPY)	≤	39.0 % (bounding value from SER for BWRVIP-74-A)
Therefore, the vessel welds are bounded by this Equivalent Margin Analysis.		

(1) The 54 EFPY adjusted decrease was evaluated for license renewal using the formulas for the curves in Figures 1 and 2 of RG 1.99, rather than by reading values off the curves. This resulted in a larger adjustment based on surveillance data than was used for the 33.1 EFPY projections.

4.2.3 Adjusted Reference Temperature Analysis

In addition to USE, the other key parameter that characterizes the fracture toughness of a material is the RT_{NDT}. This reference temperature changes as a function of exposure to neutron radiation resulting in an adjusted reference temperature, ART.

The initial RT_{NDT} is the reference temperature for the unirradiated material as defined in Paragraph NB-2331 of Section III of the ASME Boiler and Pressure Vessel Code. The change due to neutron radiation is referred to as ΔRT_{NDT}.

The ART is calculated by adding the initial RT_{NDT}, the ΔRT_{NDT}, and a margin to account for uncertainties as prescribed in Regulatory Guide 1.99, Revision 2.

The ART evaluations of record for the vessel beltline plates and welds for the currently licensed period (33.1 EFPY), including power uprate conditions, are provided in NEDO-33144 (Reference 4.8-5). NEDO-33144 lists the initial RT_{NDT} and chemistry values for the Columbia reactor vessel materials obtained from the Columbia vessel Certified Material Test Reports. Some chemistry factors were adjusted when Surveillance Capsule Data and Integrated Surveillance Program (ISP) best estimates were available, as described in NEDO-33144.

The results and methodology in NEDO-33144, Revision 2 of Regulatory Guide 1.99 (Reference 4.8-6), and the projected fluence values listed in Table 4.2-1 were used to project the ART for 54 EFPY. The results of this projection are summarized in Table 4.2-5 for vessel beltline plates and welds. The ART values projected to 54 EFPY are used to develop P-T limit curves, as discussed in Section 4.2.4. Projected ART values are well below the 200°F end of life ART suggested in Section 3 of Regulatory Guide 1.99 and are, thus, acceptable for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(ii) – Reactor vessel adjusted reference temperature TLAAs have been projected to the end of the period of extended operation.

Table 4.2-5
ART Values for 54 EFPY

Sub-Component [1]	Heat or Heat/Lot [1]	% Cu	% Ni	Chemistry Factor	Initial RT_{NDT} °F	¼T Fluence n/cm^2	ΔRT_{NDT} °F	σ_1	σ_Δ	Margin °F	ART °F
PLATES:											
Lower Shell (Course #1)	C1272-1	0.15	0.60	110	28	2.71E+17	22.8	0	11.4	22.8	73.6
	C1273-1	0.14	0.60	100	20	2.71E+17	20.7	0	10.4	20.7	61.4
	C1273-2	0.14	0.60	100	4	2.71E+17	20.7	0	10.4	20.7	45.4
	C1272-2	0.15	0.60	110	0	2.71E+17	22.8	0	11.4	22.8	45.6
Lower-Intermediate Shell (Course #2)	B5301-1 [2]	0.13	0.50	88	-20	8.10E+17	33.1	0	16.5	33.1	46.2
	C1336-1	0.13	0.50	88	-8	8.10E+17	33.1	0	16.5	33.1	58.2
	C1337-1	0.15	0.51	105	-20	8.10E+17	39.5	0	17.0	34.0	53.5
	C1337-2	0.15	0.51	105	-20	8.10E+17	39.5	0	17.0	34.0	53.5
NOZZLES:											
N6 (RHR / LPCI)	Q2Q55W 790S	0.11	0.76	76.4	-20	4.48E+17	21.1	1.4	10.5	21.1	22.2

Table 4.2-5 (continued)
ART Values for 54 EFPY

Sub-Component [1]	Heat or Heat/Lot [1]	% Cu	% Ni	Chemistry Factor	Initial RT_{NDT} °F	¼T Fluence n/cm²	ΔRT_{NDT} °F	σ_1	σ_Δ	Margin °F	ART °F
WELDS:											
Lower Vertical (Axial/Longitudinal)	04P046 / D217A27A	0.06	0.9	82	-48	2.71E+17	17.0	0	8.5	17.0	-14.0
	07L669 / K004A27A	0.03	1.02	41	-50	2.71E+17	8.5	0	4.2	8.5	-33.0
	3P4966/ 1214-3482 (S) 3P4966 / 1214-3482 (T)	0.025	0.913	34	-30 -48	2.71E+17	7.0	0	3.5	7.0	-15.9 -33.9
	C3L46C / J020A27A	0.02	0.87	27	-20	2.71E+17	5.6	0	2.8	5.6	-8.8
	08M365 / G128A27A	0.02	1.10	27	-48	2.71E+17	5.6	0	2.8	5.6	-36.8
	09L853 / A111A27A	0.03	0.86	41	-50	2.71E+17	8.5	0	4.2	8.5	-33.0
Lower-Intermediate Vertical (Axial/Longitudinal)	3P4966 / 1214-3481 (S) 3P4966 / 1214-3481 (T)	0.025	0.913	34	-20 -6	8.10E+17	12.8	0	6.4	12.8	5.6 19.7
	04P046 / D217A27A	0.06	0.90	82	-48	8.10E+17	30.8	0	15.4	30.8	13.7
	05P018 / D211A27A	0.09	0.90	122	-38	8.10E+17	45.9	0	22.9	45.9	53.8
	624063 / C228A27A	0.03	1.00	41	-50	8.10E+17	15.4	0	7.7	15.4	-19.2
	624039 / D224A27A	0.07	1.01	95	-36	8.10E+17	35.7	0	17.9	35.7	35.5
	624039 / D205A27A	0.10	0.92	134	-50	8.10E+17	50.4	0	25.2	50.4	50.8
Lower to Lower-Intermediate Girth (Circumferential)	492L4871 / A422B27AF	0.03	0.98	41	-50	3.30E+17	9.5	0	4.8	9.5	-31.0
	04T931 / A423B27AG	0.03	1.00	41	-50	3.30E+17	9.5	0	4.8	9.5	-31.0
	5P6756 / 0342-3477	0.08	0.936	153.97[2]	-50	3.30E+17	35.7	0	17.9	35.7	21.4
	3P4955 / 0342-3443 (S) 3P4955 / 0342-3443 (T)	0.027	0.921	37	-16 -20	3.30E+17	8.6	0	4.3	8.6	1.2 -2.8

(1) For weld materials, (S) = Single Wire; (T) = Tandem Wire.

(2) Adjusted chemistry factor determined per NEDO-33144, Section 4.2.1.1 (Reference 4.8-5), which was approved by the NRC in an SER (Reference 4.8-2), and updated per Columbia specific Integrated Surveillance Program (ISP) data.

4.2.4 Pressure-Temperature Limits

To ensure that adequate margins of safety are maintained for various modes of reactor operation, 10 CFR 50, Appendix G specifies pressure and temperature requirements for affected materials for the service life of the reactor vessel. The basis for these fracture toughness requirements is ASME Section XI, Appendix G. The ASME Code requires P-T limits be established for hydrostatic pressure tests and leak tests; for operation with the core not critical during heatup and cooldown; and for core critical operation.

The Columbia P-T limit curves were revised in 2005 to include the effects of power uprate to 3486 MWt (Reference 4.8-2). The P-T limits are valid for 33.1 EFPY through the end of the currently licensed period. P-T limits for the period of extended operation will be calculated using the most accurate fluence projections available at the time of the recalculation. The projections may be adjusted if there are changes in core design or if additional surveillance capsule results show the need for an adjustment. The projected ART for the period of extended operation, see Section 4.2.3 above, gives confidence that future P-T curves will provide adequate operating margin.

License amendment requests to revise the P-T limits will be submitted to the NRC for approval, when necessary to comply with 10 CFR 50 Appendix G, as part of the Reactor Vessel Surveillance Program.

Disposition: 10 CFR 54.21(c)(1)(iii) – Reactor vessel pressure-temperature limits will be adequately managed for the period of extended operation as part of the Reactor Vessel Surveillance Program.

4.2.5 Reactor Vessel Circumferential Weld Inspection Relief

BWRVIP-74-A (Reference 4.8-7) reiterated the recommendation of BWRVIP-05 (Reference 4.8-8) that RPV circumferential welds could be exempted from examination. The NRC safety evaluation report (SER) for BWRVIP-74 agreed, but required that plants apply for this relief request individually. The relief request should demonstrate that at the expiration of the current license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the (BWRVIP-05) evaluation. This evaluation of circumferential weld mean adjusted reference temperature is a TLAA.

Energy Northwest analysis of the conditional probability of failure for the Columbia RPV circumferential welds is consistent with the position in BWRVIP-05 and NRC Generic Letter 98-05. The NRC concluded that the conditional probability of failure for the Columbia RPV circumferential welds was sufficiently low to justify elimination of the volumetric examinations through 33.1 EFPY (Reference 4.8-9).

Table 4.2-6 shows that the Columbia reactor pressure vessel circumferential (girth) weld parameters at 54 EFPY will remain within the NRC's (64 EFPY) bounding vessel parameters from the BWRVIP-05 SER. As such, the conditional probability of failure for circumferential welds remains below that stated in the NRC's Final Safety Evaluation of BWRVIP-05.

Disposition: 10 CFR 54.21(c)(1)(ii) – Reactor vessel circumferential weld TLAAs have been projected to the end of the period of extended operation.

Table 4.2-6
Circumferential Weld Parameters at 54 EFPY

Parameter Description	**Columbia's Limiting Weld Wire (5P6756) 54 EFPY**	**NRC Limiting Plant Specific Analyses Parameters at 64 EFPY**
Weld Copper content, %	0.08	0.10
Weld Nickel Content, %	0.936	0.99
Weld Chemistry Factor, °F	153.97	134.9
End-of-life RPV inside diameter neutron fluence , n/cm^2	4.78E+17	1.02E+19
Initial (unirradiated) reference temperature (RT_{NDT}), °F	-50	-65
Increase in reference temperature due to irradiation (ΔRT_{NDT}), °F	44.0	135.6
Mean adjusted reference temperature (Mean ART = $RT_{NDT} + \Delta RT_{NDT}$), °F	-6.0	70.6

4.2.6 Reactor Vessel Axial Weld Failure Probability

The NRC SER for BWRVIP-74-A (Reference 4.8-7) evaluated the failure frequency of axially oriented welds in BWR reactor vessels and determined that this failure frequency is below 5.0E-06 per reactor year for 40 years of reactor operation. Applicants for license renewal must evaluate axially oriented RPV welds to show that their failure frequency remains below the 5.0E-06 value calculated in the BWRVIP-74 SER. The SER states that an acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER. The mean RT_{NDT} value from Table 1 of the SER for BWRVIP-74 that corresponds to a failure frequency of 5.0E-6 (for Pilgrim, a BWR/3) is 114°F. This 114 °F is below the 117 °F determined in Table 2.6-5 of the SER for BWRVIP-05 (Reference 4.8-15) for Chicago Bridge & Iron vessels (similar to the

Columbia RPV). Columbia will compare to the more limiting value from the SER for BWRVIP-74.

Table 4.2-7 shows that the Columbia limiting axial weld mean RT_{NDT} at 54 EFPY is only 16.9 °F. The Columbia axial weld mean RT_{NDT} remains well below the 114 °F from the SER for BWRVIP-74, thus the Columbia axial weld failure frequency is well below the acceptable limit of 5.0E-6.

Disposition: 10 CFR 54.21(c)(1)(ii) – Reactor vessel axial weld TLAAs have been projected to the end of the period of extended operation.

Table 4.2-7
Axial Weld Parameters at 54 EFPY

Parameter Description	Columbia's Bounding Axial Weld Heat/Lot 05P018/D211A27A
Weld Copper content, %	0.09
Weld Nickel Content, %	0.90
Weld Chemistry Factor, °F	122
RPV inside diameter neutron fluence , n/cm^2	1.17E+18
Initial (unirradiated) reference temperature (RT_{NDT}), °F	-38
Increase in reference temperature due to irradiation (ΔRT_{NDT}), °F	54.9
Mean adjusted reference temperature (Mean ART = RT_{NDT} + ΔRT_{NDT}), °F	16.9

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4.3 METAL FATIGUE

Fatigue evaluations for mechanical components are identified as TLAAs; therefore, the effects of fatigue must be addressed for license renewal. Fatigue is an age-related degradation mechanism caused by cyclic duty on a component by either mechanical or thermal loads.

The primary code governing design and construction of the systems, structures, and components (SSCs) of interest is the ASME Boiler and Pressure Vessel Code. The ASME Code requires evaluation of transient thermal and mechanical load cycles for Class 1 components. Design cycles and fatigue usage for Columbia are provided in stress reports for the Class 1 components and summarized in FSAR Section 3.9 and FSAR Table 3.9-1.

Class 1 SSCs include the reactor pressure vessel and reactor coolant pressure boundary components. Evaluation of fatigue for the reactor vessel is provided in Section 4.3.1. Fatigue of the non-Class 1 reactor vessel internals is addressed in Section 4.3.2. Fatigue of Class 1 reactor coolant pressure boundary piping and piping components is addressed in Section 4.3.3.

Calculation of fatigue usage values is not required for non-Class 1 SSCs. Instead, stress intensification factors and lower stress allowables are used to ensure components are adequately designed for fatigue.

Certain components of the Primary Containment were evaluated for fatigue. Results of evaluations are provided in Section 4.6.

The evaluation of reactor coolant environmental effects on fatigue of plant components is provided in Section 4.3.5.

The design cycles for Columbia are summarized in FSAR Section 3.9 and FSAR Table 3.9-1. FSAR Table 3.9-1 is reproduced as Table 4.3-1. Columbia counts all fatigue significant cycles, not only for the design transients listed in FSAR Table 3.9-1 but also for the analysis of other plant components. The events listed in FSAR Table 3.9-1 have been evaluated and in some cases regrouped for easier counting. Faulted conditions listed in the FSAR are not used in the fatigue analyses and are not counted. Additional transients determined to be fatigue significant after the original design have been added to the counting procedure, while FSAR Table 3.9-1 lists the original design cycles. The projected number of occurrences of design transients to 60 years, as shown in Table 4.3-2, determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. The last column of Table 4.3-2 lists the number of cycles that will be used for any future fatigue analyses (including the environmental fatigue analysis discussed Section 4.3.5). Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

Table 4.3-1
Plant Events (FSAR Table 3.9-1)

Conditions	Number of Cycles
Normal, upset, and testing	
Bolt up/unbolt [a, b]	123
Design pressure hydrostatic test [b]	130
Startup (100 °F/hr heatup rate) [b, c, f]	117
Daily reduction to 75 % power [a]	10,000
Weekly reduction to 50 % power [a]	2,000
Control rod pattern change [a]	400
Loss of feedwater heaters (80 cycles total) [b]	80
Operating basis earthquake event at rated operating conditions	10/50 [d]
Scrams	
Turbine generator trip, feedwater on, isolation valves stay open [b]	40
Other scrams [b]	140
Loss of feedwater pumps, isolation valves closed [b]	10
Single safety or relief valve blowdown [b, f]	8
Reduction to 0 % power, hot standby, shutdown (100 °F/hr cooldown rate) [b, c, f]	111
High-pressure core spray operation (10), standby liquid control operation (10), low-pressure core spray operation (10), and low-pressure coolant injection operation (10) [b]	40
Emergency	
Scrams	
Reactor overpressure with delayed scram feedwater stays on, isolation valves stay open [f]	1 [e]
Automatic blowdown	1 [e]
Improper start of cold recirculation loop	1 [e]
Sudden start of pump in cold recirculation loop	1 [e]
Improper startup with reactor drain shutoff followed by turbine roll and increase to rated power	1 [e]
Faulted	
Pipe rupture	1 [e]
Safe shutdown earthquake at rated operating conditions	1 [e]
ASME hydrostatic test	
1.25 x design pressure hydrostatic test ASME Section III, NB-6222 and NB-3114, allows up to 10 of these tests without stress calculation	No additional

Notes:
- [a] Applies to reactor pressure vessel only.
- [b] Thermal cycles are tracked for indication of reactor cumulative fatigue usage.
- [c] Bulk average vessel coolant temperature change in any 1-hr period.
- [d] Includes 50 peak operating basis earthquake (OBE) cycles for NSSS piping and 10 peak OBE cycles for other NSSS equipment and components. Fifty peak OBE cycles are postulated for all BOP piping and components.
- [e] The annual encounter probability of the one-cycle events is 10^{-2} for emergency and 10^{-4} for faulted events.

f Columbia is analyzed for 120 startups and shutdowns. The 120 startups consist of 117 normal startups and 3 natural circulation startups. The 120 shutdowns consist of 111 normal shutdowns, 8 single safety or relief valve blowdowns, and 1 rapid depressurization with delayed trip.

Table 4.3-2
Actual Cycles and Projected Cycles

Conditions	Analyzed cycles	Actual cycles 12/13/1984 through 7/31/2007	60 year (12/13/2044) projection(3)	Cycles for future analyses(4)
Boltup/Unbolt	123	21	55	60
Reactor Startup (100 degF/hr)	120	88	233	250
Reactor Shutdown (100 degF/hr)	111	87	230	242
Vessel Pressure Tests	130	2(1, 2)	2(1)	60
Loss of Feedwater Heaters	80	0	0	80
Scram - Loss of feedwater pumps, isolation valves closed	10	7	18	20
Scram - Single safety relief valve blowdown	8	0	0	8
Scram - TG trip, FW on, isolation valves open	40	22	58	60
Scram - Other	140	34	90	90
LPCS operation	10	0	0	10
HPCS operation	10	4	10	10(4)
LPCI operation	10	0	0	10
SLC operation	10	0	0	10

(1) Vessel hydrostatic pressure tests are no longer performed. Vessel operational leak tests have replaced the hydrostatic pressure tests.
(2) These two pressure tests were hydrostatic pressure tests.
(3) Projections were not changed for those events that have not occurred.
(4) The 20 Scrams with Loss of Feedwater assume 3 HPCS injections per scram. The HPCS initiation assumes 10 additional injections without a scram. The HPCS nozzle is analyzed for 70 cycles combined from the two events.

4.3.1 Reactor Pressure Vessel Fatigue Analyses

The reactor vessel assembly consists of the pressure vessel, the vessel support skirt, the shroud support, nozzles, penetrations, stub tubes, head closure flanges, head closure studs, refueling bellows support, and stabilizer brackets.

The materials, fabrication procedures, and testing methods used in the construction of the reactor pressure vessel meet the requirements of ASME Section III, Class 1 vessels. Codes and standards, design criteria, and specification definitions for reactor vessel assembly structures and components are provided in FSAR Section 5.3.

Design cumulative usage factors for the limiting RPV assembly locations based on the original analyzed values obtained from design reports are summarized in Table 4.3-3. These cumulative usage factors (CUFs) were calculated based on the design transients listed in Table 4.3-2.

The projected number of occurrences of design transients to 60 years, as shown in Table 4.3-2, determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

Disposition: **10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended functions of the RPV will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.**

Table 4.3-3
Fatigue Usage for Reactor Vessel Locations

Location:	CUF of Record
Base plate	0.003
Core DP nozzle stub tube	0.125
Core spray nozzle forging	0.018
Core spray nozzle safe end	0.801
Core spray nozzle sleeve	0.005
Core spray nozzle stub	0.187
CRD housing	0.196
CRD return nozzle safe end	0.543
CRD return nozzle forging	0.330
CRD stub tube	0.083
Drain nozzle	NA
FW nozzle forging	0.000
FW nozzle safe end	0.696
FW nozzle thermal sleeve	0.013
FW nozzle-shell junction	0.650
Instrument Nozzles (N12, N13, N14)	NA
Jet pump instrumentation nozzle (N9)	NA
MS nozzle forging	0.340
MS nozzle safe end	0.030

Location:	CUF of Record
MS nozzle shell	0.470
Refueling bellows support	0.453
RHR/LPCI nozzle forging	0.116
RHR/LPCI safe end	0.157
RHR/LPCI safe end ext.	0.189
RHR/LPCI thermal sleeve	0.430
RRC inlet nozzle forging	0.22
RRC inlet nozzle safe end	0.214
RRC inlet nozzle thermal sleeve	0.0013
RRC outlet nozzle clad	0.005
RRC outlet nozzle forging	0.24
RRC outlet nozzle safe end	0.005
Shroud support - Inconel	0.399
Shroud support – low-alloy steel	0.102
Stabilizer bracket	0.678
Steam dryer brackets	0.064
Support skirt	0.064
Top head flange	0.855
Vessel head spray nozzle	0.249
Vessel studs	0.985

4.3.2 Reactor Vessel Internals

This section includes fatigue analyses of the overall reactor vessel internals performed as part of the plant design, as well as fatigue analyses of jet pumps performed in response to operating conditions.

4.3.2.1 Internals Fatigue Analyses

The RPV internals are described in terms of two assemblies: Core Support Structures and Reactor Internals. Core Support Structures include the shroud, shroud support (included as part of the reactor vessel for fatigue), core plate with wedges and hold-down bolts, top guide, fuel supports, and control rod guide tubes. Reactor internals include the jet pump assemblies, jet pump instrumentation, feedwater spargers, vessel head spray line, differential pressure line, incore flux monitor guide tubes, initial startup neutron sources (removed), surveillance sample holders, core spray lines (in-vessel) and spargers, incore instrument housings, LPCI coupling, steam dryer, shroud head and steam separator assembly, guide rods, and control rod drive (CRD) thermal sleeves.

Design cumulative usage factors for the limiting reactor vessel internals locations are obtained from design reports and are summarized in Table 4.3-4. These CUFs were calculated based on the design transients listed in Table 4.3-2.

The projected number of occurrences of design transients to 60 years, as shown in Table 4.3-2, determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

Disposition: **10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended functions of the reactor vessel internals will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.**

Table 4.3-4
CUFs for Reactor Vessel Internals

Location	CUF
Core spray sparger	0.20
Core spray piping	0.0598
Shroud (top guide wedge to shroud junction)	0.316
Shroud head bolt	0.047
Top guide (longest beam)	0.1625
CRD indicator tube	0.093
CRD outer tube	0.41
CRD cylinder	0.08
CRD index tube	0
CRD piston tube	0.3
CRD pressure housing	0.003
Incore guide tube	<1
Core Δp / LC	<0.01
Core plate	0.005
LPCI coupling	0.004
Jet pump riser brace	0.920[1]
Vessel head spray line assembly	0.640

(1) The jet pump riser brace was analyzed in significant detail in response to an operating event at Columbia. This CUF contains usage for 1.5 times the design cycles shown in Table 4.3-2 plus operation at unbalanced flow plus the remainder of 60 years at balanced flow. See Section 4.3.2.2 for details.

4.3.2.2 Jet Pump Fatigue Analyses

In August 2000, Columbia operated for a period of time with the recirculation pumps in an unbalanced mode (pump speeds different by more than 50 percent). The effect of that flow imbalance on the fatigue usage of the jet pumps was an additional 0.0035.

Inspections during the Spring 2001 outage (R-15) identified gaps in the jet pump set screws. To justify operation through cycle 16, a fatigue analysis of the jet pumps was done. The original fatigue a usage factor for all jet pumps was 0.50 due to the design cycles. The additional usage due to the gaps is 0.119 for jet pumps 1 and 6 (risers 1/2 and 5/6) plus a usage of 0.001 for the unbalanced flow event. This gives a cumulative usage factor of 0.620 for risers 1/2 and 5/6 while retaining the original 0.50 for the other eight risers.

Jet pump clamps were installed on all 20 jet pumps during R-17 (2005). Each jet pump mixer was clamped to its diffuser to minimize flow induced vibration caused by leakage at the mixer to diffuser slip joint interface. As long as the set screw gaps remain within their revised criteria, no additional fatigue due to bypass leakage flow induced vibration is accumulated. These clamps greatly reduced the future potential for riser brace fatigue.

The latest gap status was reviewed after the 2007 outage. The usage factors were extended to 60 years by assuming the usage due to design cycles would increase from 0.5 to 0.75. Further assuming no subsequent unbalanced flow operation and no subsequent operation with gaps, results in a cumulative usage factor of 0.87 (0.75 + 0.119 + 0.001) for risers 1/2 and 5/6 and 0.75 for the other eight risers. The maximum 60-year CUF of any jet pump riser has been conservatively projected at 0.920.

The projected number of occurrences of design transients to 60 years, as shown in Table 4.3-2, determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached. The Fatigue Monitoring Program will also monitor the occurrence of design cycles and will monitor the jet pump gaps, effectively managing the fatigue of the jet pumps through the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(iii) - The effects of aging on the intended functions of the jet pumps will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.**

4.3.3 Reactor Coolant Pressure Boundary Piping and Piping Component Fatigue Analyses

Fatigue analyses of Class 1 piping are based on the transients found in the Columbia Piping Specification that are in turn based on the design transients listed in FSAR Section 3.9. The Class 1 boundary encompasses all reactor coolant pressure boundary piping (pipe and fittings) and in-line components subject to ASME Section XI, Subsection IWB, inspection requirements. FSAR Tables 3.2-1, 3.2-2, and 3.2-3 give codes and standards, design criteria, and specification definitions for Class 1 piping. These components are generally designed in compliance with ASME Section III, Subsection NB-3600 (NC-3600 for ≤1" piping).

FSAR Section 3.6.2 indicates that potential intermediate high energy line break locations can be eliminated based on CUFs being less than 0.1 if other stress criteria are also met. The usage factors, as calculated in the design fatigue analyses, account for the design transients assumed for the original 40-year life of the plant. Therefore, the determination of cumulative usage factors used in the selection of postulated high energy line break locations are TLAAs The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed numbers of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the design calculations for that system will be reviewed to determine if any additional locations should be designated as postulated high energy line breaks, under the original criteria of FSAR Section 3.6. If other locations are determined to require consideration as postulated break locations, actions will be taken to address the new break locations.

During initial plant startup, an induction heating stress improvement (IHSI) process was used on various RPV nozzles to safe end and safe end to pipe welds. In the 1994 refueling outage, Columbia performed a mechanical stress improvement process (MSIP) for multiple RPV nozzles to safe end and safe end to pipe welds. No credit is taken for MSIP or IHSI in the calculation of CUFs for the Columbia vessel nozzles and safe ends.

All Class 1 piping was reviewed for the power uprate. The power uprate evaluation scaled existing fatigue analyses based on the changes in stress expected from the power uprate. This evaluation showed that there was adequate margin in each system to accommodate the power uprate (the increased CUF after the power uprate was approximated by the report). The maximum CUFs for Class 1 piping are shown in Table 4.3-5. The Fatigue Monitoring Program uses the systematic counting of plant transient cycles to ensure that component design fatigue usage limits are not exceeded. Design fatigue usage for 40 years of operation is provided in Table 4.3-5 for the limiting reactor coolant pressure boundary components.

A review of Columbia's documentation found several fatigue analyses for Class 1 valves that were TLAAs. The fatigue usage for those valves is based on transients that are tracked by the Fatigue Monitoring Program. The maximum CUFs for any Class 1 valves is 0.84 for the head spray inside containment check valve and 0.6599 for five 12 inch containment isolation valves. These CUFs are included in Table 4.3-5.

Metal fatigue for all Class 1 reactor coolant pressure boundary piping and in-line components (as listed in Table 4.3-5) is managed by the Fatigue Monitoring Program. The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed numbers of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the design calculations for that system will be reviewed and appropriate actions will be taken.

Disposition: **10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended functions of the reactor coolant pressure boundary piping and components will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.**

Table 4.3-5
CUFs for Reactor Pressure Boundary Piping and Piping Components

System or Component	Max CUF
Reactor Feedwater Line A	0.250
Reactor Feedwater Line B	0.137
Reactor Feedwater / RWCU	0.588
Main Steam Line A	0.446
Main Steam Line B	0.7225
Main Steam Line C	0.222
Main Steam Line D	0.647
Main Steam Isolation Valves	0.0093
Reactor Recirculation Loop A	0.850
Reactor Recirculation Loop B	0.920
Reactor Recirculation Isolation Valves	0.0036
Reactor Water Cleanup	0.152
High Pressure Core Spray	0.237
Low Pressure Core Spray	0.145
Residual Heat Removal	0.001
Reactor Core Isolation Cooling	0.487
Reactor Vessel Head Spray	0.209
Reactor Vessel Head Vent to Main Steam	0.940
Reactor Vessel Level Instrument Lines and Condensing Pots	0.49
Standby Liquid Control System	0.262
Head spray check valve	0.84
12 inch containment isolation valves (5)	0.6599

4.3.4 Non-Class 1 Component Fatigue Analyses

The specific codes and standards to which SSCs were designed are listed in FSAR Table 3.2-1 and FSAR Table 3.2-2.

Non-class 1 components that are Quality Group B or C are designed and constructed to the ASME Boiler and Pressure Vessel Code. The design of ASME III Code Class 2 and 3 piping systems incorporates a cycle based stress range reduction factor for determining acceptability of piping design with respect to thermal stress range. Columbia SSCs designated as quality group D are designed to ANSI B31.1, which also incorporates stress range reduction factors based upon the number of thermal cycles. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to 7,000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7,000. If fewer than 7,000 cycles are expected through the period of extended operation, then the fatigue analysis (stress range reduction factor) of record will remain valid through the period of extended operation.

The non-Class 1 aging management reviews for Columbia determined piping locations susceptible to fatigue. The fatigue evaluation of non-Class 1 components determined whether the associated operating temperature exceeded threshold values for the affected materials and, if so, evaluated the number of transient cycles expected. In every case, the number of projected cycles for 60 years was found to be less than 7,000 for piping and in-line components whose temperatures exceed threshold values. Therefore, fatigue for non-Class 1 piping and in-line components remains valid for the period of extended operation.

None of the non-Class 1 vessels, heat exchangers, storage tanks, or pumps were designed to ASME Section VIII, Division 2 or ASME Section III, Subsection NC-3200. Therefore, there is no fatigue TLAA for these components.

Disposition: 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation.

4.3.5 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping

4.3.5.1 Background

The NRC requires applicants for license renewal to address the reactor coolant environmental effects on fatigue of plant components (NUREG-1800 Section 4.3). The minimum set of components for a BWR of Columbia's vintage is derived from NUREG/CR-6260 (Reference 4.8-10), as follows:

1. Reactor vessel shell and lower head
2. Reactor vessel feedwater nozzle
3. Reactor recirculation piping (including inlet and outlet nozzles)
4. Core spray line reactor vessel nozzle and associated Class 1 piping
5. Residual heat removal return line Class 1 piping
6. Feedwater line Class 1 piping

In NUREG-1800, the NRC mentions using the calculational approach whereby the fatigue life adjustment factor (F_{en}) is determined for each fatigue-sensitive component and applying those environmental fatigue correction factors to the component CUFs to verify acceptability of the components for the period of extended operation. In NUREG-1800, the NRC further points out equations for calculating F_{en} values as being those contained in NUREG/CR-6583 (Reference 4.8-11) for carbon steel and low alloy steel components and in NUREG/CR-5704 (Reference 4.8-12) for austenitic stainless steel components. Nickel alloy components were also analyzed using the stainless steel equations in NUREG/CR-5704.

Environmentally assisted fatigue (EAF) evaluations are not applied during the current licensing basis. EAF evaluations done for the period of extended operation apply the EAF correction factors per NUREG-6260.

4.3.5.2 Columbia Evaluation

Using projected cycles from the Fatigue Monitoring Program and methodology accepted by the NRC, as noted above, the limiting locations (a total of 14 component locations corresponding to the six NUREG/CR-6260 components) for the material for each component location were evaluated. None of the 14 locations evaluated have an environmentally adjusted CUF of greater than 1.0 (see Table 4.3-6).

Values for dissolved oxygen, before and after the adoption of Hydrogen Water Chemistry (HWC), were used in the F_{en} determination. The plant operated with Normal Water Chemistry (NWC) for 20.9 years from January 19, 1984 (initial startup) until November 28, 2004. The plant has operated with HWC from November 28, 2004, and is assumed to continue operating with HWC until January 13, 2044; a combined time of

39.1 years. The time Columbia has operated under both NWC (21 years) and HWC (39 years) conditions was considered in the estimation of an effective F_{en} based on a time weighted average of the HWC and NWC F_{en} values over 60 years of operation. The cumulative fatigue usage factor incorporating the effects of reactor coolant environment is obtained by multiplying the usage factor by F_{en}.

Original fatigue usage calculations were reviewed, and the transient groupings and load pairs used in those analyses were carried over to the EAF analyses. This ranged from a single transient grouping with a single load pair for the RRC inlet nozzle safe end to nearly a dozen load pairs and individual transients for the feedwater nozzle and RRC piping. For each load pair, a value of F_{en} was calculated. The environmentally adjusted usage factor for each load pair was then obtained by multiplying the usage factor by the F_{en} for that load pair. The environmentally adjusted cumulative usage factor for each location was obtained by summing the individual environmentally adjusted usage factors for each load pair.

The environmentally-adjusted CUFs for Columbia are shown in Table 4.3-6. The minimum F_{en} for any load pair, the maximum F_{en} for any load pair, and an "average F_{en}" for each location is given. The average F_{en} is simply the final environmentally assisted CUF divided by the non-environmentally assisted CUF.

Columbia will manage the aging effect of fatigue for the period of extended operation, with consideration of the environmental effects using the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

Disposition: **10 CFR 54.21(c)(1)(iii) – The effects of environmentally-assisted fatigue will be adequately managed for the period of extended operation using the Fatigue Monitoring Program.**

Table 4.3-6
CUFs for NUREG/CR-6260 Locations

NUREG/CR-6260 generic locations		Columbia plant-specific locations	Material type	Revised CUF in air (2)	Per NUREG/CR-5704 and NUREG/CR-6583			
					Min. F_{en} (3)	Average F_{en} (3)	Max. F_{en} (3)	Environmentally assisted CUF
1	Reactor vessel shell and lower head	CRD stub tube	Nickel Alloy	0.0125	12.90	12.90	12.90	0.162
1	Reactor vessel shell and lower head	CRD housing	SS	0.0007	12.90	12.90	12.90	0.0088
2	Reactor vessel feedwater nozzle	FW nozzle to shell junction (1)	LAS	0.132	3.04	6.72	20.52	0.887
2	Reactor vessel feedwater nozzle	FW nozzle safe end (1)	Nickel Alloy	0.00126	3.29	4.77	6.43	0.00601
3	Reactor recirculation piping (including inlet and outlet nozzles)	Reactor vessel RRC inlet nozzle safe end	SS	0.026	12.90	12.90	12.90	0.335
3	Reactor recirculation piping (including inlet and outlet nozzles)	Reactor vessel RRC outlet nozzle forging	LAS	0.054	10.51	10.51	10.51	0.567
3	Reactor recirculation piping (including inlet and outlet nozzles)	RRC piping	SS	0.373	2.55	2.66	12.90	0.994
4	Core spray line reactor vessel nozzle and associated Class 1 piping	Reactor vessel nozzle safe end – Core Spray	Nickel Alloy	0.241	2.55	3.95	3.96	0.953

Table 4.3-6 (continued)
CUFs for NUREG/CR-6260 Locations

NUREG/CR-6260 generic locations		Columbia plant-specific locations	Material type	Revised CUF in air (2)	Per NUREG/CR-5704 and NUREG/CR-6583			
					Min. F_{en} (3)	Average F_{en} (3)	Max. F_{en} (3)	Environmentally assisted CUF
4	Core spray line reactor vessel nozzle and associated Class 1 piping	LPCS piping	CS	0.155	1.74	5.22	7.33	0.809
4	Core spray line reactor vessel nozzle and associated Class 1 piping	HPCS piping	CS	0.321	1.74	2.25	2.49	0.723
5	Residual Heat Removal (RHR) nozzles and associated Class 1 piping	RHR/LPCI nozzle safe end	Nickel Alloy	0.139	2.55	6.16	6.94	0.856
5	Residual Heat Removal (RHR) nozzles and associated Class 1 piping	RHR/LPCI nozzle safe end extension	CS	0.190	1.74	2.39	2.75	0.455
5	Residual Heat Removal (RHR) nozzles and associated Class 1 piping	RHR/LPCI piping	CS	0.001	20.49	20.49	20.49	0.02
6	Feedwater line Class 1 piping	RFW/RWCU Tee (1)	CS	0.210	1.74	1.85	2.85	0.389

Note: CS is carbon steel, LAS is low alloy steel, SS is stainless steel

(1) Assumed NWC dissolved oxygen concentration equaled to 150 ppb for the RFW nozzle and RFW/RWCU Tee F_{en} calculation.

(2) CUF of record previously identified in Table 4.3-3 and Table 4.3-5.

(3) Effective F_{en} determined for each load pair based on a time weighted average for HWC and NWC for 60 years of operation. Average F_{en} is the reported environmentally assisted CUF divided by the non-environmentally assisted CUF.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

Environmental qualification (EQ) analyses for those components with a qualified life of 40 years or greater are identified as TLAAs. NRC regulation 10 CFR 50.49 "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants" requires licensees to identify electrical equipment covered under this regulation and to maintain a qualification file demonstrating that the equipment is qualified for its application and will perform its safety function up to the end of its qualified life. The EQ Program implements the requirements of 10 CFR 50.49 and will be used to manage the effects of aging on the intended functions of the components associated with EQ TLAAs for the period of extended operation.

Review of Columbia EQ qualification information documents (QIDs) for electrical equipment concluded that the majority are TLAAs. There are 113 QIDs for equipment covered by 10 CFR 50.49. Of these, 100 are TLAAs because they meet all six of the criteria established in the TLAA definition of 10 CFR 54.3. The remaining 13 are not TLAAs because the subject equipment has a qualified life of less than 40 years.

The EQ TLAAs were evaluated per 10 CFR 54.21(c)(1). Any required update of the QIDs will be performed in accordance with the EQ Program requirements and processes. Update of the QIDs is not a license renewal commitment. The license renewal commitment is that the EQ Program will be used to manage aging of EQ components. Ultimately any needed updates of the QIDs to extend qualified life prior to entering the period of extended operation will be driven by the EQ Program, using the same methodology as in the current license term to ensure components do not exceed their qualified life. The updates may include re-analysis of the qualified life, refurbishment of the equipment, or replacement of the equipment. A re-analysis will be performed in a timely manner (that is, with sufficient time available to refurbish, replace, or re-qualify the component if the re-analysis is unsuccessful). The EQ Component Re-analysis Attributes (from NUREG-1800, Table 4.4-1) are addressed below.

EQ Component Re-analysis Attributes

The re-analysis of an aging evaluation is normally performed to extend the qualification of the component by reducing excess conservatism incorporated in the previous evaluation. Re-analysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Columbia EQ Program. A component's life-limiting condition may be due to thermal, radiation, or cyclical aging; however, the majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed peak ambient temperature of the component, an unrealistically low activation energy, or in the specific application of a component (energized vs. de-energized). The re-analysis of an aging evaluation is documented according to Columbia quality assurance program requirements, which require the verification of assumptions and conclusions. As already noted, important attributes of a re-analysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if the acceptance criteria are not met). These attributes are discussed below.

Analytical Methods

The Columbia EQ Program uses the same analytical models in the re-analysis of an aging evaluation as those applied during the previous qualification analysis. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years divided by 40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, an approach similar to that used for radiation dose may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods

Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the previous aging evaluation is a method used for a re-analysis in the Columbia EQ Program. Temperature data used in an aging evaluation should be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors installed on large motors (while the motor is not running). A representative number of temperature measurements are evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as: a) directly applying the plant temperature data in the evaluation, or b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a re-analysis must be justified. Similar methods of reducing excess conservatism in the component service conditions used in previous aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions

The Columbia EQ Program environmental qualification evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant conditions and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated, and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions

Under the Columbia EQ Program, the re-analysis of an aging evaluation could extend the qualification of a component. If the qualification cannot be extended by re-analysis, the component must be refurbished, replaced, or re-qualified prior to exceeding the current qualified life. A re-analysis should be performed in a timely manner (such that sufficient time is available to refurbish, replace, or re-qualify the component if the re-analysis is unsuccessful).

Therefore, the EQ TLAAs are dispositioned per 10 CFR 54.21(c)(1)(iii). The Columbia EQ Program is part of the current licensing basis, is in compliance with 10 CFR 50.49, and is the basis for managing the aging of EQ equipment in the current license term.

In Section X.E1 of NUREG-1801, the NRC has already generically evaluated EQ programs put in place to meet 10 CFR 50.49 and found them acceptable for managing the aging of electrical EQ equipment during the period of extended operation. NUREG-1800, Section 4.4.2.1.3, states that if a licensee takes credit for this generic evaluation of the EQ Program, "...the applicant should indicate that the material referenced is applicable to the specific plant involved and should provide the information necessary to adopt the finding of program acceptability as described and evaluated in this report." To this end, a comparison of the EQ Program to the evaluation in NUREG-1801, Section X.E1 was performed with the results documented in Appendix B of this Application. From this review, it was concluded that the Columbia EQ Program contains the same program elements evaluated in NUREG-1801 and that the EQ Program is consistent with the generic evaluation performed by the NRC and documented in NUREG-1801. Continued effective implementation of the Columbia EQ Program assures that the aging effects will be adequately managed and that EQ components will continue to perform their intended functions for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended functions of the EQ components will be adequately managed for the period of extended operation by the EQ Program.

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4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

Section 4.5 of NUREG-1800 addresses the issue of TLAAs associated with concrete containment tendon prestress. Columbia has a Mark II primary containment, and this structure does not contain pre-stressed tendons. Therefore, evaluations for tendon prestress are not applicable to Columbia.

Disposition: TLAAs for tendon prestress are not applicable to Columbia.

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4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSES

The Columbia Primary Containment utilizes a GE Mark II over-under pressure-suppression configuration. The drywell and suppression chamber (or wetwell) are large sealed volumes designed to contain and condense escaping reactor coolant. Both contain structures and piping systems with the suppression chamber approximately half filled with water (suppression pool) for steam quenching. The drywell is connected to the suppression pool by 99 downcomer pipes (3 of the 102 original pipes have been capped) that channel steam released during a LOCA for quenching and pressure suppression. (see FSAR Section 3A.3.2.1)

Codes and standards for the containment structure are given in FSAR Section 3.8.2.2 and FSAR Table 3.8-4. The cycles used in the fatigue evaluation of the containment components is given in FSAR Table 3A.4.1-3, which is reproduced below.

No operating basis earthquake has occurred through 2007, and thus are projected to remain within the 5 analyzed events through 60 years. The safe shutdown earthquake and post-LOCA chugging are once in a lifetime events and thus will not exceed the one analyzed event through 60 years of operation.

A review of plant data indicates that no more than 636 SRV cycles have occurred through 2007. This conservatively projects to 2,400 cycles through 60 years of operation, and remains well below the 13,434 cycles that have been analyzed. The fatigue analyses performed using these cycles will remain valid for the period of extended operation, as indicated by the table below.

FSAR Table 3A.4.1-3
Equivalent Stress Cycles for Fatigue Evaluation

Load	Number of Events	Number of Equivalent Stress Cycles per Event	Total Number of Stress Cycles
Operating basis earthquake	5	10	50
Safe shutdown earthquake	1	10	10
SRV [a]	4,478	3	13,434
Chugging	1	1,000	1,000

a This includes the cycles due to building motion, direct pressure, and fluid transients during SRV actuations.

As the cycles on which the containment fatigue analysis is based will not be exceeded for 60 years of operation, the analyses discussed in the following sections will remain valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(i) – The TLAAs associated with fatigue of the containment remain valid for the period of extended operation.

4.6.1 ASME Class MC Components

Class MC components include the primary containment vessel shell, large openings (equipment hatch, personnel hatches, and access hatch), penetrations (all except the large openings), and attachments (pipe supports in the wetwell, welding pads in the drywell, supports for the stabilizer truss, seal and shear lugs at the drywell floor, supports for the downcomer bracing system, pipe whip supports, radial beam supports, cap truss supports, catwalks, monorail, and platforms). The Class MC components were analyzed for fatigue using the transients listed in FSAR Table 3A.4.1-3, reproduced in Section 4.6 above. As these cycles will not be exceeded for 60 years of operation, the Class MC component fatigue analysis will remain valid for the period of extended operation.

A specific fatigue analysis was performed for the main steam penetrations. Main steam penetrations were analyzed using the transients listed in FSAR Table 3A.4.1-3, reproduced in Section 4.6 above. The maximum revised CUF was 0.174. As this CUF was calculated based on the cycles identified above, this analysis will remain valid for the period of extended operation.

In May 1995, the NRC staff granted Columbia an amendment to the operating license to allow an increase in the power level of the plant (Reference 4.8-13). For short-term containment pressure response, the peak pressure values are below design values and remain virtually unaffected by power uprate and extended load line limit. The loss-of-coolant accident (LOCA) containment dynamic loads are not affected by power uprate, and SRV containment loads will remain below their design allowables. (see FSAR Appendix 3A)

All events project to remain below the containment cyclic basis from FSAR Table 3A.4.1-3 for 60 years of operation as discussed in Section 4.6 above. Consequently, the analysis of the Class MC containment components remains valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(i) - The TLAAs for fatigue of the ASME Class MC components remain valid through the end of the period of extended operation.

4.6.2 Downcomers

There are 84 24-inch diameter downcomers and 18 28-inch downcomers. Three of the downcomers are capped (see FSAR Section 6.2.1.1.3.2).

The downcomer vent pipes are designed to contain and direct uncondensed drywell steam into the suppression pool following a pipe break accident. The upper portion of the downcomers are designed and constructed in accordance with ASME Section III Class 2 requirements while the lower portion are designed and constructed to ASME Section III Class 3 requirements. The only effect of this code break is to eliminate radiography requirements for the circumferential weld joining the upper and lower portions of the downcomers (see FSAR Section 3.8.3.4.9).

A fatigue evaluation of the downcomers was performed even though it is not an ASME Code requirement. The fatigue evaluation of the downcomer lines in the wetwell air volume was based on the number of cycles as presented in FSAR Table 3A.4.1-3 (reproduced in Section 4.6 above). The maximum fatigue usage factor for the 24-inch downcomers is 0.0346 and the maximum usage factor for the 28-inch downcomers is 0.0629. (see FSAR Table 3A.4.2-4 and Table 3A.4.2-5)

All events project to remain below the containment cyclic basis from FSAR Table 3A.4.1-3 for 60 years of operation as discussed in Section 4.6 above. Consequently, the analysis of the downcomers remains valid for the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(i) - The TLAA for fatigue of the downcomers remains valid through the end of the period of extended operation.**

4.6.3 Safety Relief Valve Discharge Piping

Each of the 18 SRVs on the main steam lines in the drywell chamber have a discharge line into the wetwell that terminates in a quencher in the suppression pool. To pass through the drywell floor, the discharge lines are routed through downcomers. (see FSAR Section 3A.3.1.1)

A fatigue evaluation of the SRV discharge piping was performed even though it is not an ASME Code requirement. The fatigue evaluation used the number of cycles as presented in FSAR Table 3A.4.1-3, reproduced in Section 4.6 above. The maximum fatigue usage factor for all 18 SRV discharge lines in the wetwell air volume was found to be 0.896, below ASME allowable limits of 1.0 (see FSAR Section 3A.4.2.4.6).

All events project to remain below the containment cyclic basis from FSAR Table 3A.4.1-3 for 60 years of operation as discussed in Section 4.6 above. Consequently, the analysis of the SRV discharge piping remains valid for the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(i) - The TLAA for fatigue of the SRV discharge piping remains valid through the end of the period of extended operation.**

4.6.4 Diaphragm Floor Seal

The diaphragm floor seal is located at the inside surface of the primary containment vessel periphery. It provides a flexible, pressure tight seal between the primary containment vessel and the diaphragm floor and is capable of accommodating differential thermal expansion between them.

The fatigue evaluation was performed using the cycles in Section 4.6 above. The maximum CUF is 0.7 per FSAR Table 3A.4.1-5. All events project to remain below the containment cyclic basis from FSAR Table 3A.4.1-3 for 60 years of operation as discussed in Section 4.6 above. Consequently, the analysis of the diaphragm floor seal remains valid for the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(i) - The TLAA for fatigue of the diaphragm floor seal remains valid through the end of the period of extended operation.**

4.6.5 ECCS Suction Strainers

The original Columbia ECCS suction strainers were replaced with a new strainer design constructed from cold-worked austenitic stainless steel. A linear elastic fracture mechanics analysis was performed to bound all the martensitic material in the suction strainer screens. A crack depth was assumed based on the depth of the Alpha Prime martensite in the strainer screen material.

Cyclic stresses were included in the crack growth analysis of the suction strainers. The fatigue crack evaluation determined that the assumed cracks will not propagate to a critical size for the remaining life of the plant. The maximum computed stress intensity value (K) was less than that required to cause cracking in Alpha martensite formed in austenitic stainless steel.

The stress value included direct pressure and inertial components from SRV actuation, OBE loads, and SRV steam chugging. (see FSAR Table 3A.4.1-3 as reproduced in Section 4.6 above.)

All events are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3 for 60 years of operation as discussed in Section 4.6 above. Consequently, the analysis of the ECCS suction strainers remains valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(i) - The TLAA for crack growth of the ECCS suction strainers remains valid through the end of the period of extended operation.

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4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

4.7.1 Reactor Vessel Shell Indications

Two indications in the reactor vessel shell were identified using ultrasonic testing methods during the 2005 inservice inspections. The indications were present in past inservice inspection examinations, but became rejectable under current ASME Section XI, IWB-3610 requirements. The rejected indications were evaluated and determined to be acceptable for continued service without repair, as reported to the NRC in Energy Northwest letter GO2-05-153 (Reference 4.8-14). The indications were evaluated per the guidelines of ASME Section XI, IWB-3610, which include acceptance criteria based on the applied stress intensity factors, using conservative assumptions in the applied stresses to determine the stress intensity factors for comparison to Code allowables.

This evaluation calculated a fatigue crack growth (0.0064 inches) at the end of 33.1 EFPY vessel service life that is insignificant in comparison to the bounding initial crack size of 0.39 inch. It also determined that the applied stress intensity factor (about 30 ksi$\sqrt{in}$) is well below the allowable K_{IC} of 63.25 ksi$\sqrt{in}$.

The calculation used two time-limited assumptions based on the 40-year life of the plant, and thus is a TLAA.

1. The ¼ T neutron fluence at weld BG (5.11E+17 n/cm^2 at 33.1 EFPY) was used for both welds. This fluence was used to calculate the material properties of the cracked area, and hence the crack propagation. As can be seen from Table 4.2-1, the projected ¼ T fluence for Weld BG at 54 EFPY is 8.10E+17 n/cm^2.
2. 500 significant thermal transients were assumed (SRV blowdown cycles being the worst case thermal cycle). From Table 4.3-2, it can be seen that no SRV blowdown cycles are expected through 60 years of operation; furthermore, only 409 significant thermal transients are expected (233 heatup/cooldowns, 166 scrams, and 10 HPCS actuations).

Although this calculation easily meets the acceptance criteria, it is based on a time-limited assumption of neutron fluence that will not remain valid for the period of extended operation. This indication is currently scheduled for re-inspection in 2015. Columbia will re-evaluate the indication based on the results of the 2015 inspection and either project this analysis through the period of extended operation or continue augmented inspections as required by the ASME code. As such, Columbia will manage the aging of the reactor vessel shell indications using the Inservice Inspection (ISI) Program for the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(iii) - Cracking of the reactor vessel shell near welds BG and BM will be adequately managed through the period of extended operation by the Inservice Inspection (ISI) Program.**

4.7.2 Sacrificial Shield Wall

The sacrificial shield wall (SSW) is discussed in FSAR Section 3.8.3.6, which states "It has been determined that in the 40-year life expectancy of the station, the outside face of the SSW will experience a neutron fluence of less than 2 x 10^{16} nvt." (For the discussion in this section, nvt is equivalent to n/cm^2 with neutron energy greater than 1 MeV).

Projected fluence at the SSW outer wall for 60 years of operation, including an increase in the neutron flux at the SSW of 5.28 percent due to power uprate, remains below 2 x 10^{16} nvt. As the estimated neutron fluence on the sacrificial shield wall is projected to remain below the FSAR value for 60 years, this TLAA has been projected through the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(ii) - The TLAA associated with the sacrificial shield wall fluence has been projected to the end of the period of extended operation.**

4.7.3 Main Steam Line Flow Restrictor Erosion Analyses

FSAR Section 5.4.4 indicates that a main steam line flow restrictor is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line between the last main steam line SRV and the inboard main steam isolation valve (MSIV). The restrictor is designed to limit coolant flow rate from the reactor vessel (before the MSIVs are closed) to less than 200 percent of normal flow in the event a main steam line break occurs outside the containment. The restrictor assembly has no moving parts and consists of a venturi-type nozzle insert welded into the main steam line.

FSAR Section 5.4.4.4 indicates that only very slow erosion of the main steam flow restrictor is expected. Erosion of a flow restrictor is a safety concern since it could impair the ability of the flow restrictor to limit vessel blowdown following a main steam line break. Since erosion is a time-related phenomenon, the analysis for the effect it has on the flow restrictors over the life of the plant is a TLAA. Cast stainless steel (SA351, Type CF8) was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion from high velocity steam.

Columbia has projected the erosion of the main steam flow restrictors for the period of extended operation. The projection concludes that after 60 years of erosion on the main steam flow restrictors, the choked flow will still be less than 200 percent of normal flow. Therefore, the main steam flow restrictors will continue to perform their intended function for the period of extended operation.

Disposition: **10 CFR 54.21(c)(1)(ii) - The TLAA for erosion of the main steam line flow restrictors has been projected to the end of the period of extended operation.**

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4.8 REFERENCES

4.8-1 GO2-04-107, Energy Northwest Letter to USNRC Document Control Desk, "License Amendment Request to Revise Technical Specification 3.4.11 Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits," June 9, 2004 (includes excerpts from NEDO-33144).

4.8-2 GI2-05-076, NRC to J.V. Parrish (Energy Northwest), "Columbia Generating Station – Issuance of Amendment RE: Reactor Coolant System (RCS) Pressure and Temperature Limits," May 12, 2005 (includes SER).

4.8-3 General Electric Report GE-NE-0000-0023-5057-R0, "Energy Northwest Columbia Generating Station Neutron Flux Evaluation," April 2004 (GE Proprietary Information).

4.8-4 NRC letter, S. A. Richard, USNRC, to J. F. Klaproth, GE-NE, "Safety Evaluation for NEDC-32983P, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation (TAC No. MA9891)", MFN 01-050, September 14, 2001.

4.8-5 General Electric Report NEDO-33144, "Pressure-Temperature Curves for Energy Northwest Columbia," April 2004 (Non-proprietary version of NEDO-33144P).

4.8-6 NRC Regulatory Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Revision 2.

4.8-7 BWRVIP-74-A: "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," EPRI, Palo Alto, CA: 2003. 1008872. (EPRI Proprietary).

4.8-8 BWRVIP-05: "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," EPRI, Palo Alto, CA. 1995. 105697. (EPRI Proprietary).

4.8-9 GI2-05-090, NRC to J.V. Parrish (Energy Northwest), "Safety Evaluation for Columbia Generating Station – Relief Request for Alternatives to Volumetric Examination of Reactor Pressure Vessel Circumferential Shell Welds in Accordance with BWRVIP-05 (TAC No. MC3916)," June 1, 2005.

4.8-10 NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995.

4.8-11 NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998.

4.8-12 NUREG/CR-5704, "Effects of LW Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999.

4.8-13 GI2-95-099, J. W. Clifford (NRC) to J. V. Parrish, "Issuance of Amendment for the Washington Public Power Supply System Nuclear Project No. w (TAC Nos. M87076 and M88625)," May 2, 1995.

4.8-14 GO2-05-153, W Oxenford (Energy Northwest) Letter to NRC Document Control Desk, "Columbia Generating Station, Docket No. 50-397 Analytical Evaluation of Inservice Inspection Examination Results," September 15, 2005.

4.8-15 NRC letter, Gus C. Lainas to Carl Terry, BWRVIP Chairman, "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)," July 28, 1998.

APPENDIX A

FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

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A.0 FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

A.1 INTRODUCTION

This appendix provides the information to be submitted in a Final Safety Analysis Report (FSAR) Supplement as required by 10 CFR 54.21(d) for the License Renewal Application (LRA). The LRA contains the technical information required by 10 CFR 54.21(a) and (c). Section 3 of the LRA contains the results of the aging management reviews. The programs and activities credited to manage the effects of aging are described in LRA Appendix B. Section 4 of the LRA documents the evaluations of time-limited aging analyses for the period of extended operation. LRA Section 3, Section 4, and Appendix B have been used to prepare the program and activity descriptions that are contained in this appendix. In addition, this appendix contains a listing of commitments associated with license renewal. The information presented in LRA Sections A.1.2, A.1.3, and A.1.4 will be incorporated into the FSAR following issuance of the renewed operating license. The listing of commitments for license renewal in LRA Section A.1.5 is provided for information, but will not be included in the FSAR. The license renewal commitments will be tracked within the Columbia regulatory commitment management program (see Commitment Item Number 57).

A.1.1 New FSAR Section

The information contained in LRA Sections A.1.2, A.1.3, and A.1.4 will be incorporated into the FSAR to document aging management programs and activities credited in the Columbia integrated plant assessment and time-limited aging analyses evaluated for the period of extended operation.

A.1.2 Aging Management Program and Activities

The license renewal integrated plant assessment identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities identified during the integrated plant assessment. The aging management programs will be implemented prior to the period of extended operation. One-time inspections will be conducted within the 10-year period prior to beginning the period of extended operation. The aging management programs identified as necessary in association with the evaluation of time-limited aging analyses are described in Section A.1.3.

Three elements of an effective aging management program that are common to each of the aging management programs are corrective actions, confirmation process, and administrative controls. These elements are included in the Operational Quality

Assurance Program Description (OQAPD) for Columbia, which implements the requirements of 10 CFR 50, Appendix B.

Prior to the period of extended operation, the elements of corrective actions, confirmation process, and administrative controls in the OQAPD will be applied to required aging management programs for both safety-related and non-safety related structures and components determined to require aging management during the period of extended operation.

A.1.2.1 Aboveground Steel Tanks Inspection

The Aboveground Steel Tanks Inspection detects and characterizes the conditions on the bottom surfaces of the condensate storage tanks. The inspection provides direct evidence through volumetric examination as to whether, and to what extent, a loss of material due to corrosion has occurred in inaccessible areas (i.e., tank base and bottom surface).

The Aboveground Steel Tanks Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.2 Air Quality Sampling Program

The Air Quality Sampling Program is an existing prevention and condition monitoring program that manages loss of material due to corrosion for Diesel Starting Air (DSA) components that contain compressed air through periodic sampling of the air for hydrocarbons, dewpoint, and particulates and periodic ultrasonic inspection of the DSA System air receivers. In addition, the Air Quality Sampling Program ensures that the Control Air System remains dry and free of contaminants, such that no aging effects require management.

The Air Quality Sampling Program is supplemented by the Diesel Starting Air Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging in the DSA System dryers and the downstream piping and components (excluding the DSA System air receivers).

A.1.2.3 Appendix J Program

The Appendix J Program is an existing monitoring program that detects degradation of the Primary Containment and systems penetrating the Primary Containment, which are the containment shell and primary containment penetrations including (but not limited to) the personnel airlock, equipment hatch, control rod drive hatch, and drywell head. The Appendix J Program provides assurance that leakage from the Primary Containment will not exceed maximum values for containment leakage.

A.1.2.4 Bolting Integrity Program

The Bolting Integrity Program is a combination of existing activities that, in conjunction with other credited programs, address the management of aging for the bolting of mechanical components and structural connections within the scope of license renewal. The Bolting Integrity Program relies on manufacturer and vendor information and industry recommendations for the proper selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections. The Bolting Integrity Program includes, through the Inservice Inspection (ISI) Program, Inservice Inspection (ISI) Program – IWF, Structures Monitoring Program, and External Surfaces Monitoring Program, the periodic inspection of bolting for indications of degradation such as leakage, loss of material due to corrosion, loss of pre-load, and cracking due to stress corrosion cracking (SCC) and fatigue.

A.1.2.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program manages the effects of loss of material due to corrosion on the external surfaces of piping and tanks exposed to a buried environment. The Buried Piping and Tanks Inspection Program is a combination of a mitigation program (consisting of protective coatings) and a condition monitoring program (consisting of visual inspections).

An inspection of buried piping will be performed within the 10-year period prior to entering the period of extended operation. An additional inspection of buried piping will be performed within 10 years after entering the period of extended operation.

The Buried Piping and Tanks Inspection Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.6 BWR Feedwater Nozzle Program

The BWR Feedwater Nozzle Program is an existing program that manages cracking due to stress corrosion cracking and intergranular attack (SCC/IGA) and flaw growth of the feedwater nozzles. The BWR Feedwater Nozzle Program is in accordance with ASME Section XI and NRC augmented requirements.

The BWR Feedwater Nozzle Program consists of: (a) enhanced inservice inspection in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 edition including the 2002 and 2003 Addenda) and the recommendations of General Electric report NE-523-A71-0594-A [Reference A.1.4-1], and (b) system modifications, as described in FSAR Section 5.3.3.1.4.5, to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of the feedwater nozzles.

The BWR Feedwater Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

A.1.2.7 BWR Penetrations Program

The BWR Penetrations Program is an existing condition monitoring program that manages cracking due to SCC or intergranular stress corrosion cracking (IGSCC) of reactor vessel instrument penetrations, jet pump instrument penetrations, control rod drive penetrations, and incore instrument penetrations. The BWR Penetrations Program detects and sizes cracks in accordance with the guidelines of approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) documents and the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel components.

The program credits portions of the Inservice Inspection (ISI) Program and the BWR Vessel Internals Program.

A.1.2.8 BWR Stress Corrosion Cracking Program

The BWR Stress Corrosion Cracking Program is an existing condition monitoring program that manages cracking due to SCC/IGA for stainless steel and nickel alloy reactor coolant pressure boundary piping, nozzle safe ends, nozzle thermal sleeves, valve bodies, flow elements, and pump casings.

The BWR Stress Corrosion Cracking Program consists of (a) preventive measures to mitigate SCC/IGA, and (b) inspection and flaw evaluation to monitor SCC/IGA and its effects. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term mitigation of SCC/IGA. The program includes the scope of the Generic Letter 88-01 program, as modified by the staff-approved BWRVIP-75 report.

The program credits portions of the Inservice Inspection (ISI) Program and the BWR Water Chemistry Program.

A.1.2.9 BWR Vessel ID Attachment Welds Program

The BWR Vessel ID Attachment Welds Program is an existing program that manages cracking due to SCC/IGA of the welds for internal attachments to the reactor vessel. The BWR Vessel ID Attachment Welds Program performs examinations and inspections as required by ASME Section XI, augmented by BWRVIP-48-A. These inspections include enhanced visual inspections with resolution to the guidelines in BWRVIP-03. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel internal attachment welds.

The BWR Vessel ID Attachment Welds Program credits portions of the BWR Vessel Internals Program and the Inservice Inspection (ISI) Program.

A.1.2.10 BWR Vessel Internals Program

The BWR Vessel Internals Program is an existing condition monitoring program that manages cracking due to stress corrosion cracking and irradiation assisted stress corrosion cracking (SCC/IASCC), SCC/IGA, flaw growth, and flow-induced vibration for various components and subcomponents of the reactor vessel internals. The BWR Vessel Internals Program consists of mitigation, inspection, flaw evaluation, and repair in accordance with the guidelines of BWRVIP reports and the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel internal components.

The BWR Vessel Internals Program credits portions of the Inservice Inspection (ISI) Program.

A.1.2.11 BWR Water Chemistry Program

The BWR Water Chemistry Program is an existing program that mitigates degradation of components that are within the scope of license renewal and contain or are exposed to treated water, treated water in the steam phase, reactor coolant, or treated water in a sodium pentaborate solution. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to corrosion or erosion, cracking due to SCC, or reduction in heat transfer due to fouling through proper monitoring and control of chemical concentrations consistent with BWRVIP water chemistry guidelines.

The BWR Water Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection and the Heat Exchangers Inspection, to provide verification of the effectiveness of the program in managing the effects of aging. Additionally, the BWR Water Chemistry Program is supplemented by the BWR Feedwater Nozzle Program, BWR Stress Corrosion Cracking Program, BWR Penetrations Program, BWR Vessel ID Attachment Welds Program, BWR Vessel Internals Program, Inservice Inspection (ISI) Program, and Small Bore Class 1 Piping Inspection to provide verification of the program's effectiveness in managing the effects of aging for reactor pressure vessel, reactor vessel internals, and reactor coolant pressure boundary components.

A.1.2.12 Chemistry Program Effectiveness Inspection

The Chemistry Program Effectiveness Inspection detects and characterizes the condition of materials in representative low flow and stagnant areas of systems with water chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program, and with fuel oil chemistry controlled by the Fuel Oil Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred. The inspection also determines whether cracking due to SCC of susceptible materials in susceptible locations has occurred.

The Chemistry Program Effectiveness Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.13 Closed Cooling Water Chemistry Program

The Closed Cooling Water Chemistry Program mitigates degradation of components that are within the scope of license renewal and contain closed cooling water. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to corrosion or erosion, cracking due to SCC, or reduction in heat transfer due to fouling through proper monitoring and control of corrosion inhibitor concentrations consistent with EPRI closed cooling water chemistry guidelines.

The Closed Cooling Water Chemistry Program includes corrosion rate measurement in reactor building closed cooling water locations and is supplemented by the one-time Chemistry Program Effectiveness Inspection and Heat Exchangers Inspection, which provide verification of the effectiveness of the program in managing the effects of aging.

The Closed Cooling Water Chemistry Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.14 Cooling Units Inspection

The Cooling Units Inspection detects and characterizes the material condition of aluminum, steel, copper alloy, and stainless steel cooling unit components that are exposed to condensation. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion, a reduction in heat transfer due to fouling of heat exchanger tubes and fins, or cracking due to SCC of aluminum components, has occurred.

The Cooling Units Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.15 CRDRL Nozzle Program

The CRDRL Nozzle Program is an existing mitigation and condition monitoring program that manages cracking due to flaw growth of the control rod drive return line (CRDRL) nozzle, safe end, cap, and connecting welds. The CRDRL Nozzle Program consists of a) mitigation activities, and b) inspection, flaw evaluation, and repair in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 Edition through 2003 Addenda) and the recommendations of NUREG-0619. System modifications were implemented by the original equipment manufacturer prior to initial startup to mitigate cracking. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the critical regions of the CRDRL nozzle.

The CRDRL Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

A.1.2.16 Diesel Starting Air Inspection

The Diesel Starting Air Inspection detects and characterizes the condition of materials for the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers). The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Diesel Starting Air Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.17 Diesel Systems Inspection

The Diesel Systems Inspection detects and characterizes the condition of materials for the interior of the exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping, and the drain pans and drain piping associated with air-handling units of the Diesel Building HVAC systems. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Diesel Systems Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.18 Diesel-Driven Fire Pumps Inspection

The Diesel-Driven Fire Pumps Inspection detects and characterizes the material condition of the interior of the Fire Protection System diesel engine exhaust piping, and of Fire Protection System diesel heat exchangers exposed to a raw water environment.

The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion or erosion, or a reduction in heat transfer due to fouling has occurred. The inspection also determines whether cracking due to SCC of susceptible materials has occurred.

The Diesel-Driven Fire Pumps Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.19 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is an inspection program that detects degradation of electrical cables and connections that are not environmentally qualified and are within the scope of license renewal. The program provides for periodic visual inspection of accessible, non-environmentally qualified cables and connections in order to determine if age-related degradation is occurring, particularly in plant areas with adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified design or bounding plant environment for the general area.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation. The inspection frequency of the program will be once every 10 years, with the initial inspection to be performed prior to the period of extended operation.

A.1.2.20 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a monitoring program that detects degradation of electrical cables and connections that are not environmentally qualified and used in circuits with sensitive, low-current applications (such as radiation monitoring and nuclear instrumentation loops). The program provides for a review of calibration records for the low-current instruments, in order to detect and identify degradation of the cable system insulation resistance. The program retains the option to perform direct cable testing.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new aging management program that will be implemented prior to the period of extended operation. The frequency of the program will be once every 10 years, with the initial review to be performed prior to the period of extended operation.

A.1.2.21 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection detects and characterizes the material condition of metallic electrical connections within the scope of license renewal. The inspection uses thermography (augmented by contact resistance testing) to detect loose or degraded connections that lead to increased resistance for a representative sample of metallic electrical connections in various plant locations.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.22 EQ Program

Environmental qualification (EQ) analyses for electrical components with a qualified life of 40 years or greater are identified as TLAAs; therefore, the effects of aging must be addressed for license renewal.

NRC regulation 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," requires licensees to identify electrical equipment covered under this regulation and to maintain a qualification file demonstrating that the equipment is qualified for its application and will perform its safety function up to the end of its qualified life. The EQ Program is an existing program that implements the requirements of 10 CFR 50.49 (as further defined by the Division of Operating Reactor Guidelines, NUREG-0588, and Regulatory Guide 1.89 Revision 1).

In accordance with 10 CFR 54.21(c)(1)(iii), the EQ Program will be used to manage the effects of aging on the intended functions of the components associated with EQ TLAAs for the period of extended operation.

A.1.2.23 External Surfaces Monitoring Program

The External Surfaces Monitoring Program consists of observation and surveillance activities intended to detect degradation resulting from loss of material due to corrosion and cracking due to SCC for mechanical components, as well as hardening and loss of strength for elastomers. The External Surfaces Monitoring Program is a condition-monitoring program.

The External Surfaces Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.24 Fatigue Monitoring Program

Fatigue evaluations for mechanical components are identified as TLAAs; therefore, the effects of fatigue have been addressed for license renewal.

Columbia monitors fatigue of various components (including ASME Class 1 reactor coolant pressure boundary, high energy line break locations, and Primary Containment) via the Fatigue Monitoring Program, which tracks transient cycles and calculates fatigue usage. Columbia has assessed the impact of the reactor coolant environment on the sample of critical components identified in NUREG/CR-6260. Calculation of fatigue usage values is not required for non-Class 1 SSCs. Instead, stress intensification factors and lower stress allowables are used to ensure components are adequately designed for fatigue.

In accordance with 10 CFR 54.21(c)(1)(iii), the Fatigue Monitoring Program will be used to manage the effects of aging due to fatigue on the intended functions of the components associated with fatigue TLAAs for the period of extended operation.

The Fatigue Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.25 Fire Protection Program

The Fire Protection Program is an existing program, described in Appendix F of the FSAR, that detects degradation of components in the scope of license renewal that have fire barrier functions. Periodic visual inspections and functional tests are performed of fire dampers, fire barrier walls, ceilings and floors, fire-rated penetration seals, fire wraps, fire proofing, and fire doors to ensure that functionality and operability are maintained. In addition, the Fire Protection Program supplements the Fuel Oil Chemistry Program and External Surfaces Monitoring Program through performance monitoring of the diesel-driven fire pump fuel oil supply components and testing and inspection of the halon suppression system, respectively. The Fire Protection Program is a condition monitoring program, comprised of tests and inspections based on National Fire Protection Association (NFPA) recommendations.

A.1.2.26 Fire Water Program

The Fire Water Program (sub-program of the overall Fire Protection Program) is described in Appendix F of the FSAR, and is credited with managing loss of material due to corrosion, erosion, macrofouling, and selective leaching, cracking due to SCC/IGA of susceptible water-based fire suppression components in the scope of license renewal. Periodic inspection and testing of the water-based fire suppression systems provides reasonable assurance that the systems will remain capable of performing their intended function. Periodic inspection and testing activities include hydrant and hose station inspections, fire main flushing, flow tests, and sprinkler inspections. The Fire Water Program is a condition monitoring program, comprised of tests and inspections based on NFPA recommendations.

The Fire Water Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.27 Flexible Connection Inspection

The Flexible Connection Inspection detects and characterizes the material condition of elastomer components exposed to treated water, dried air, gas, and indoor air environments. The inspection provides direct evidence as to whether, and to what extent, hardening and loss of strength has occurred.

The Flexible Connection Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.28 Flow-Accelerated Corrosion (FAC) Program

The Flow-Accelerated Corrosion (FAC) Program manages loss of material for steel and gray cast iron components located in the treated water environment of systems that are susceptible to FAC, also called erosion-corrosion. The FAC Program combines the elements of predictive analysis, inspections (to baseline and monitor wall-thinning), industry experience, station information gathering and communication, and engineering judgment to monitor and predict FAC wear rates. The program is a condition monitoring program that implements the recommendations of NRC Generic Letter 89-08, and follows the guidance and recommendations of EPRI NSAC-202L [Reference A.1.4-2], to ensure that the integrity of piping systems susceptible to FAC is maintained.

The FAC Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.29 Fuel Oil Chemistry Program

The Fuel Oil Chemistry Program is an existing program that maintains fuel oil quality in order to mitigate degradation of the storage tanks and associated components containing fuel oil that are within the scope of license renewal. The program includes diesel fuel oil testing for emergency diesel generator and diesel-driven fire pump fuel. The Fuel Oil Chemistry Program manages the relevant conditions that could lead to the onset and propagation of loss of material due to corrosion, or cracking due to SCC of susceptible copper alloys, through proper monitoring and control of fuel oil contamination consistent with plant technical specifications and American Society for Testing and Materials (ASTM) standards for fuel oil. The relevant conditions are specific contaminants such as water or microbiological organisms in the fuel oil that could lead to corrosion of susceptible materials. Exposure to these contaminants is minimized by verifying the quality of new fuel oil before it enters the emergency diesel generator storage tanks and by periodic sampling to ensure that both the emergency diesel generator tanks and fire protection tanks are free of water and particulates. The Fuel Oil Chemistry Program is a mitigation program.

The Fuel Oil Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

A.1.2.30 Heat Exchangers Inspection

The Heat Exchangers Inspection detects and characterizes the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to indoor air or to water with the chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a reduction of heat transfer due to fouling has occurred on the heat transfer surfaces of heat exchangers and coolers.

The Heat Exchangers Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.31 High-Voltage Porcelain Insulators Aging Management Program

The High-Voltage Porcelain Insulators Aging Management Program is an existing program that manages the build-up of contamination (hard water residue) on the surfaces of the 115-kV high-voltage insulators. The program provides for periodic cleaning or recoating of insulators and visual inspection of the coating (if present) on the high-voltage porcelain insulators between the 115-kV backup transformer and circuit breaker E-CB-TRB located in the station transformer yard.

The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program consisting of activities to mitigate potential degradation of the insulation function due to hard water deposits. Uncoated insulators are inspected and cleaned every two years. Coated insulators are visually inspected for damage every two years and are re-coated every 10 years.

A.1.2.32 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program manages the aging of inaccessible medium-voltage cables that are not environmentally qualified and are within the scope of license renewal. The program provides for testing to identify the conditions of the conductor insulation, and also provides for periodic inspection and drainage (if necessary) of electrical manholes.

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation. The frequency of the cable testing portion of the program will be once every 10 years, with the first test to be performed prior to the period of extended operation. The frequency of the manhole inspections will be at least once every two years, with the first inspections to be performed prior to the period of extended operation.

A.1.2.33 Inservice Inspection (ISI) Program

The Inservice Inspection (ISI) Program is an existing condition monitoring program that manages cracking due to SCC/IGA and flaw growth of multiple reactor coolant system pressure boundary components, including the reactor vessel, a limited number of internals components, and the reactor coolant system pressure boundary. The Inservice Inspection (ISI) Program also manages loss of material due to corrosion for reactor vessel internals components and reduction of fracture toughness due to thermal embrittlement of cast austenitic stainless steel pump casings and valve bodies.

The Inservice Inspection (ISI) Program details the requirements for the examination, testing, repair, and replacement of components specified in ASME Section XI for Class 1, 2, or 3 components. The Inservice Inspection (ISI) Program complies with the ASME Code requirements.

The program scope has been augmented to include additional requirements, and components, beyond the ASME requirements. Examples include the augmentation of ISI to expanded reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, and examinations per Generic Letter 88-01. Such augmentation is consistent with the ISI program description in NUREG-1801, Section XI.M1.

A.1.2.34 Inservice Inspection (ISI) Program – IWE

The Inservice Inspection (ISI) Program – IWE is an existing program that establishes responsibilities and requirements for conducting IWE inspections as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWE includes visual examination of all accessible surface areas of the steel containment and its integral attachments, and containment pressure-retaining bolting in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration for 10 CFR 54 associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

A.1.2.35 Inservice Inspection (ISI) Program – IWF

The Inservice Inspection (ISI) Program – IWF is an existing program that establishes responsibilities and requirements for conducting IWF Inspections for ASME Class 1, 2, and 3 component supports as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWF performs visual examination of supports based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1 and those other than piping supports (Class 1, 2, 3, and MC)). The sample size decreases for the less critical supports (ASME Class 2 and 3). The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. Supports requiring corrective actions are re-examined during the next inspection period in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWF.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration for 10 CFR 54 associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

A.1.2.36 Lubricating Oil Analysis Program

The Lubricating Oil Analysis Program manages loss of material due to corrosion or selective leaching of susceptible materials and reduction of heat transfer due to fouling for plant components that are within the scope of license renewal and exposed to a lubricating oil environment. The Lubricating Oil Analysis Program is a mitigation program.

The Lubricating Oil Analysis Program is supplemented by the Lubricating Oil Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

The Lubricating Oil Analysis Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.37 Lubricating Oil Inspection

The Lubricating Oil Inspection detects and characterizes the condition of materials in systems and components for which the Lubricating Oil Analysis Program is credited with aging management. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion or selective leaching has occurred. The inspection also determines whether a reduction in heat transfer due to fouling has occurred.

The Lubricating Oil Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.38 Masonry Wall Inspection

The Masonry Wall Inspection consists of inspection activities to detect cracking of masonry walls within the scope of license renewal. Masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program. The Masonry Wall Inspection is implemented as part of the Structures Monitoring Program. The Masonry Wall Inspection performs visual inspection of external surfaces of masonry walls.

The Masonry Wall Inspection is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.39 Material Handling System Inspection Program

The Material Handling System Inspection Program manages loss of material for cranes (including bridge, trolley, rails, and girders), monorails, and hoists within the scope of license renewal. The Material Handling System Inspection Program is based on guidance contained in ANSI B30.2 for overhead and gantry cranes, ANSI B30.11 for monorail systems and underhung cranes, and ANSI B30.16 for overhead hoists.

The Material Handling System Inspection Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.40 Metal-Enclosed Bus Program

The Metal-Enclosed Bus Program is an inspection program that detects degradation of metal-enclosed bus within the scope of license renewal. The program provides for the visual inspection of interior sections of bus, and an inspection of the elastomeric seals at the joints of the duct sections. The program also makes provision for thermographic inspection of bus bolted connections.

The Metal-Enclosed Bus Program is a new aging management program that will be implemented prior to the period of extended operation. The thermography portion of the program will be performed once every 10 years, with the initial inspections to be performed prior to the period of extended operation. The visual inspection portion of the program will also be performed once every 10 years, with the first inspections to be performed prior to the period of extended operation.

A.1.2.41 Monitoring and Collection Systems Inspection

The Monitoring and Collection Systems Inspection detects and characterizes the condition of materials at the internal surfaces of subject mechanical components that are exposed to equipment or area drainage water and other potential contaminants and fluids. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion or erosion has occurred. The inspection also determines whether cracking due to SCC of susceptible materials has occurred.

The Monitoring and Collection Systems Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.42 Open-Cycle Cooling Water Program

The Open-Cycle Cooling Water Program manages cracking due to SCC of susceptible materials and loss of material due to corrosion and erosion for components located in the Standby Service Water and Plant Service Water systems, and for components connected to or serviced by those systems. The program manages fouling due to particulates (e.g., corrosion products) and biological material (micro- or macro-organisms) resulting in reduction in heat transfer for heat exchangers (including condensers, coolers, cooling coils, and evaporators) within the scope of the program. The Open-Cycle Cooling Water Program also manages loss of material for components associated with the feed-and-bleed mode for emergency makeup water to the spray pond.

The Open-Cycle Cooling Water Program consists of inspections, surveillances, and testing to detect the presence, and assess the extent of cracking, fouling, and loss of material. The inspection activities are combined with chemical treatments and cleaning activities to minimize the effects of aging. The program is a combination condition monitoring and mitigation program that implements the recommendations of NRC Generic Letter 89-13 for safety-related equipment in the scope of the program. The scope of the program also includes non-safety related components containing either service water or spray pond makeup water.

The Open-Cycle Cooling Water Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.43 Potable Water Monitoring Program

The Potable Water Monitoring Program is a mitigation program that, by means of chemical water treatment, manages loss of material due to corrosion and erosion for components that contain potable water.

The Potable Water Monitoring Program is an existing program that requires enhancement prior to the period of extended operation. At least one inspection will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.44 Preventive Maintenance – RCIC Turbine Casing

Preventive Maintenance – RCIC Turbine Casing is an existing program that manages loss of material due to corrosion for the reactor core isolation cooling (RCIC) pump turbine casing and associated piping components downstream from the steam admission valve. These components are exposed to steam during RCIC system operation and testing, but are empty during normal plant operating conditions. Preventive Maintenance – RCIC Turbine Casing is a condition monitoring program comprised of periodic inspection and surveillance activities to detect aging and age-related degradation.

A.1.2.45 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program is an existing program that manages cracking due to SCC and loss of material due to corrosion for the reactor head closure stud assemblies (studs, nuts, washers, and bushings). The Reactor Head Closure Studs Program examines reactor vessel stud assemblies in accordance with the examination and inspection requirements specified in the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB (edition and addenda described in the Inservice Inspection (ISI) Program), Table IWB 2500-1. The Reactor Head Closure Studs Program includes preventive measures in accordance with Regulatory Guide 1.65 to mitigate cracking.

The Reactor Head Closure Studs Program credits portions of the Inservice (ISI) Inspection Program.

A.1.2.46 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program is an existing condition monitoring program that manages reduction of fracture toughness due to radiation embrittlement for the low alloy steel reactor vessel shell and welds in the beltline region. The Reactor Vessel Surveillance Program incorporates the BWRVIP Integrated Surveillance Program (ISP), as described in reports BWRVIP-86-A and BWRVIP-116.

Energy Northwest follows the requirements of the BWRVIP ISP and applies the ISP data to Columbia. The NRC has approved the use of the BWRVIP ISP in place of a unique plant program for Columbia.

The provisions of 10 CFR 50 Appendix G require Columbia to operate within the currently licensed pressure-temperature (P-T) limit curves, and to update these curves as necessary. The P-T limit curves, as contained in plant technical specifications, will be updated as necessary through the period of extended operation as part of the Reactor Vessel Surveillance Program. Reactor vessel P-T limits will thus be managed for the period of extended operation.

A.1.2.47 Selective Leaching Inspection

The Selective Leaching Inspection detects and characterizes the conditions on internal and external surfaces of subject components exposed to raw water, treated water, fuel oil, soil, and moist air (including condensation) environments. The inspection provides direct evidence through a combination of visual examination and hardness testing, or NRC-approved alternative, as to whether, and to what extent, a loss of material due to selective leaching has occurred.

The Selective Leaching Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.48 Service Air System Inspection

The Service Air System Inspection detects and characterizes the material condition of steel piping and valve bodies exposed to an "air (internal)" (i.e., compressed air) environment within the license renewal boundary of the Service Air System. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Service Air System Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.49 Small Bore Class 1 Piping Inspection

The Small Bore Class 1 Piping Inspection will detect and characterize the conditions on the internal surfaces of small bore Class 1 piping components that are exposed to reactor coolant. The Small Bore Class 1 Piping Inspection will provide physical evidence as to whether, and to what extent, cracking due to SCC or to thermal or mechanical loading has occurred in small bore Class 1 piping components. The Small Bore Class 1 Piping Inspection will also verify, by inspections for cracking, that reduction of fracture toughness due to thermal embrittlement requires no additional aging management for small bore cast austenitic stainless steel valves.

The Small Bore Class 1 Piping Inspection includes visual and volumetric inspection of a representative sample of small bore Class 1 piping components. The inspection provides additional assurance that cracking of small bore Class 1 piping is not occurring or is insignificant, such that an aging management program is not warranted during the period of extended operation. This one-time inspection is appropriate as Columbia has not experienced cracking of small bore Class 1 piping from stress corrosion or thermal and mechanical loading. Should evidence of significant aging be revealed by the one-time inspection or through plant operating experience, periodic inspection will be considered as a plant-specific aging management program.

The Small Bore Class 1 Piping Inspection credits portions of the Inservice Inspection (ISI) Program. The Small Bore Class 1 Piping Inspection is credited to verify the effectiveness of the BWR Water Chemistry Program in mitigating cracking of small bore piping and piping components.

The Small Bore Class 1 Piping Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the portion of the fourth 10-year ISI interval that occurs prior to the period of extended operation.

A.1.2.50 Structures Monitoring Program

The Structures Monitoring Program manages age-related degradation of plant structures and structural components within its scope to ensure that each structure or structural component retains the ability to perform its intended function. Aging effects are detected by visual inspection of external surfaces prior to the loss of the structure's or component's intended function. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection and the Masonry Wall Inspection. This program implements provisions of the Maintenance Rule, 10 CFR 50.65, that relate to structures, masonry walls, and water control structures. Concrete and masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program.

The Structures Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.1.2.51 Supplemental Piping/Tank Inspection

The Supplemental Piping/Tank Inspection detects and characterizes the material condition of steel, gray cast iron, and stainless steel components exposed to moist air environments. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Supplemental Piping/Tank Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.52 Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will manage reduction of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals.

The program includes: (a) identification of susceptible components determined to be limiting from the standpoint of thermal aging or neutron irradiation embrittlement (neutron fluence), (b) a component-specific evaluation to determine each identified component's susceptibility to reduction of fracture toughness, and (c) a supplemental examination of any component not eliminated by the component-specific evaluation.

The program credits portions of the Inservice Inspection (ISI) Program and the BWR Vessel Internals Program.

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new aging management program that will be implemented prior to the period of extended operation.

A.1.2.53 Water Control Structures Inspection

The Water Control Structures Inspection, implemented as part of the Structures Monitoring Program, consists of inspection activities to detect aging and age-related degradation. The Water Control Structures Inspection ensures the structural integrity and operational adequacy of the spray ponds, standby service water pump houses, circulating water pump house (including circulating water basin), makeup water pump house, cooling tower basins, and those structural components within the structures.

The Water Control Structures Inspection is an existing program that requires enhancement prior to the period of extended operation.

A.1.3 Evaluation of Time-Limited Aging Analyses

In accordance with 10 CFR 54.21(c), an application for a renewed operating license requires an evaluation of TLAAs for the period of extended operation. The following TLAAs have been identified and evaluated to meet this requirement.

A.1.3.1 Reactor Vessel Neutron Embrittlement

Neutron embrittlement is the change in mechanical properties of reactor vessel materials resulting from exposure to fast neutron flux (E>1.0 MeV) in the beltline region of the reactor core. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to crack propagation decreases. Fracture toughness is also dependent on temperature. The reference temperature for nil-ductility transition (RT_{NDT}) is the temperature above which the material behaves in a ductile manner and below which the material behaves in a brittle manner. As fluence increases, RT_{NDT} increases, and higher temperatures are required for the material to continue to act in a ductile manner.

Requirements associated with fracture toughness, pressure-temperature limits, and material surveillance programs for the reactor coolant pressure boundary are contained in Appendices G and H of 10 CFR 50.

The analyses associated with evaluation of the effect of neutron embrittlement on the reactor pressure vessel for 40 years are TLAAs. Neutron fluence, upper shelf energy, adjusted reference temperature (ART), and vessel P-T limits are time dependent parameters associated with fracture toughness (embrittlement) of reactor vessel materials.

A.1.3.1.1 Neutron Fluence

EFPY Projection

To evaluate the effects of radiation on reactor pressure vessel material embrittlement, the results of analyses were projected to determine neutron fluence out to 54 effective full power years (EFPY). Using actual reactor core power histories through 2007 and conservative estimates of future core designs, extended operation to 60 years was determined to be bounded by 54 EFPY.

Fluence Projection

Analyzed fluence values at 51.6 EFPY of reactor operation are addressed in FSAR Section 4.3.2.8 and FSAR Table 4.3-1. These fluence analyses are based on the original licensed thermal power of 3323 mega-watt thermal (MWt) through fuel cycle 10, and the currently licensed thermal power uprated to 3486 MWt from cycle 11 through the end of operation. These fluence analyses use NRC-approved methodology based on the guidance of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The fluence analyses were projected to 54 EFPY for the extended operating period of 60 years.

Beltline Evaluation

For the extended operating period, ferritic materials for vessel beltline shells, welds, and assembly components are required to be evaluated for neutron irradiation embrittlement if high energy neutron fluence is greater than a threshold value of 1E+17 n/cm^2 (E >1 MeV) at the end of the 60 years. The only vessel assembly items, other than the shells and welds of the beltline region that would experience neutron fluence greater than 1E+17 n/cm^2 during the period of extended operation are instrumentation nozzle N12 and residual heat removal/low pressure coolant injection (RHR/LPCI) nozzle N6.

Instrumentation nozzle N12 has a thickness less than 2.5 inches and therefore does not require a fracture toughness evaluation per ASME Code Appendix G, Section G2223.

Nozzle N6 is evaluated for ART below. The ART for this nozzle is less than that for the highest weld and plate. Consequently, nozzle N6 is not the limiting material for the vessel, and thus is not a beltline component. However, as nozzle N6 was evaluated for ART it meets the definition of a beltline component per 10 CFR 50, Appendix G.

The beltline definition for the period of extended operation includes the lower shell (Course #1 / Ring #21), lower-intermediate shell (Course #2 / Ring #22), associated vertical (longitudinal) welds, the girth (circumferential) weld that connects the lower and lower-intermediate shells, and nozzle N6.

Disposition

Neutron fluence is not a TLAA, it is a time-limited assumption used in various neutron embrittlement TLAAs.

A.1.3.1.2 Upper Shelf Energy Evaluation

10 CFR 50 Appendix G requires the upper shelf energy (USE) of the vessel beltline materials to remain above 50 ft-lb at all times during plant operation, including the effects of neutron radiation. If USE cannot be shown to remain above this limit, then an equivalent margin analysis (EMA) must be performed to show that the margins of safety against fracture are equivalent to those required by Appendix G of Section XI of the ASME Code.

The initial (unirradiated) USE is not known for all the Columbia vessel plates and welds. For those plates and welds for which the initial USE is known, USE was projected using Regulatory Guide 1.99, Revision 2 methods. For the vessel plates and welds for which the initial USE is not known, USE equivalent margin analyses were performed using the Boiling Water Reactor Owners Group (BWROG) equivalent margin analysis (EMA) methodology. Results from the testing and analysis of surveillance materials were used in the EMA analyses.

All of the projected USE values for the vessel beltline plates and welds for which the initial USE is known remain above 50 ft-lbs through the end of the period of extended operation (54 EFPY). For the vessel beltline plates and welds for which the initial USE is not known, the maximum decrease in USE was found to be less than the assumed decrease in the associated equivalent margin analyses. The maximum predicted decreases in USE for 54 EFPY for these beltline plates and welds are bounded by the equivalent margin analyses. Therefore, the projected USE for the vessel beltline plates and welds is acceptable for the period of extended operation.

Disposition

Reactor vessel upper shelf energy TLAAs have been projected to the end of the period of extended operation.

A.1.3.1.3 Adjusted Reference Temperature Analysis

In addition to USE, the other key parameter that characterizes the fracture toughness of a material is the RT_{NDT}. This reference temperature changes as a function of exposure to neutron radiation resulting in an adjusted reference temperature, ART.

The initial RT_{NDT} is the reference temperature for the unirradiated material. The change due to neutron radiation is referred to as ΔRT_{NDT}. The ART is calculated by adding the initial RT_{NDT}, the ΔRT_{NDT}, and a margin to account for uncertainties as prescribed in Regulatory Guide 1.99, Revision 2.

The ART evaluations of record for the vessel beltline plates and welds for the currently licensed period (33.1 EFPY) include power uprate conditions. Based on projected fluence values, the methodology in Regulatory Guide 1.99 was used to project the ART for 54 EFPY. The ART values projected to 54 EFPY are used to develop P-T limit curves. Projected ART values are well below the 200°F end of life ART suggested in Section 3 of Regulatory Guide 1.99 and are, thus, acceptable for the period of extended operation.

Disposition

Reactor vessel adjusted reference temperature TLAAs have been projected to the end of the period of extended operation.

A.1.3.1.4 Pressure-Temperature Limits

To ensure that adequate margins of safety are maintained for various modes of reactor operation, 10 CFR 50, Appendix G specifies pressure and temperature requirements for affected materials for the service life of the reactor vessel. The basis for these fracture toughness requirements is ASME Section XI, Appendix G. The ASME Code requires P-T limits be established for hydrostatic pressure tests and leak tests; for operation with the core not critical during heatup and cooldown; and for core critical operation.

The Columbia P-T limit curves were revised in 2005 to include the effects of power uprate to 3486 MWt. The P-T limits are valid for 33.1 EFPY through the end of the currently licensed period. P-T limits for the period of extended operation will be calculated using the most accurate fluence projections available at the time of the recalculation. The projections may be adjusted if there are changes in core design or if additional surveillance capsule results show the need for an adjustment. The projected ART for the period of extended operation gives confidence that future P-T curves will provide adequate operating margin.

License amendment requests to revise the P-T limits will be submitted to the NRC for approval, when necessary to comply with 10 CFR 50 Appendix G, as part of the Reactor Vessel Surveillance Program.

Disposition

The TLAA for P-T limits will be adequately managed for the period of extended operation as part of the Reactor Vessel Surveillance Program.

A.1.3.1.5 Reactor Vessel Circumferential Weld Inspection Relief

BWRVIP-74-A, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," reiterated the recommendation of BWRVIP-05, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," that vessel circumferential welds could be exempted from examination. The NRC safety evaluation report (SER) for BWRVIP-74 agreed, but required that plants apply for this relief request individually. The relief request is required to demonstrate that at the expiration of the current license, the circumferential welds will satisfy the limiting conditional failure probability in the (BWRVIP-05) evaluation. Energy Northwest requested and received permanent relief from vessel shell circumferential (girth) weld volumetric examinations through 33.1 EFPY.

The reactor pressure vessel circumferential weld parameters at 54 EFPY have been projected to remain within the bounding (64 EFPY) vessel parameters from the BWRVIP-05 SER. As such, the conditional probability of failure for circumferential welds remains below the limits contained in the SER for BWRVIP-05.

Disposition

The TLAA for reactor vessel circumferential weld examination relief has been projected to the end of the period of extended operation.

A.1.3.1.6 Reactor Vessel Axial Weld Failure Probability

The NRC SER for BWRVIP-74-A evaluated the failure frequency of axially oriented welds in BWR reactor vessels, and determined failure frequency acceptance criteria for 40 years of reactor operation. Applicants for license renewal are required to evaluate axially oriented vessel welds to show that their failure frequency remains below the acceptance criteria in the SER for BWRVIP-74. An acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER.

The Columbia limiting axial weld mean RT_{NDT} at 54 EFPY is projected to remain well below the RT_{NDT} from the SER for BWRVIP-74, thus the Columbia axial weld failure frequency meets the acceptable criteria.

<u>Disposition</u>

The TLAA for the reactor vessel axial weld failure probability has been projected to the end of the period of extended operation.

A.1.3.2 Metal Fatigue

Fatigue evaluations for mechanical components are identified as TLAAs; therefore, the effects of fatigue must be addressed for license renewal. Fatigue is an age-related degradation mechanism caused by cyclic duty on a component by either mechanical or thermal loads.

The ASME Boiler and Pressure Vessel Code requires evaluation of transient thermal and mechanical load cycles for Class 1 components. Cumulative usage factors for Class 1 components are calculated based on normal and upset design transient definitions. The design transients used to generate cumulative usage factors for Class 1 components are contained in FSAR Section 3.9.1.1. Columbia is required to monitor design transients listed in FSAR Table 3.9-1 to ensure that plant components are maintained within the design limits.

Calculation of fatigue usage values is not required for non-Class 1 SSCs. Instead, stress intensification factors and lower stress allowables are used to ensure components are adequately designed for fatigue.

The reactor coolant environmental effects of fatigue on plant components were also evaluated.

The design cycles for Columbia are summarized in FSAR Section 3.9 and FSAR Table 3.9-1. Columbia counts all fatigue significant cycles, not only for the design transients listed in FSAR Table 3.9-1 but also for the analysis of other plant components. The events listed in FSAR Table 3.9-1 have been evaluated and in some cases regrouped for easier counting. Faulted conditions listed in the FSAR are not used in the fatigue analyses and are not counted. Additional transients determined to be fatigue significant after the original design have been added to the counting procedure, while FSAR Table 3.9-1 lists the original design cycles. The projected number of occurrences of design transients to 60 years determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

A.1.3.2.1 Reactor Pressure Vessel Fatigue Analyses

The reactor vessel assembly consists of the reactor pressure vessel (RPV), the vessel support skirt, the shroud support, nozzles, penetrations, stub tubes, head closure flanges, head closure studs, refueling bellows support, and stabilizer brackets.

Design cumulative usage factors (CUFs) for the limiting RPV assembly locations are contained in design reports and were calculated based on the design transients. Columbia manages fatigue for the RPV assembly components using the Fatigue Monitoring Program to track transient cycles and requires corrective action before any analyzed number of cycles is reached.

<u>Disposition</u>

The effects of aging on the intended functions of the RPV will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.1.3.2.2 Reactor Pressure Vessel Internals

Fatigue analyses of the overall RPV internals (including the jet pump assemblies) were performed pre-startup as part of the plant design. Component specific fatigue analyses of the jet pumps were performed more recently to bound actual plant operation. Each of these analyses is discussed below.

<u>Reactor Vessel Internals Fatigue Analyses</u>

The RPV internals are described in terms of two assemblies: core support structures and reactor internals. Core support structures include the shroud, shroud support (included as part of the reactor vessel for fatigue), core plate with wedges and hold-down bolts, top guide, fuel supports, and control rod guide tubes. Reactor internals include the jet pump assemblies, jet pump instrumentation, feedwater spargers, vessel head spray nozzle, differential pressure line, incore flux monitor guide tubes, surveillance sample holders, core spray line (in-vessel) and spargers, incore instrument housings, low pressure coolant injection coupling, steam dryer, shroud head and steam separator assembly, guide rods, and control rod drive thermal sleeves.

The normal, test, and upset service load cycles used for the design and fatigue analysis for the core support structures and reactor internals are shown in FSAR Table 3.9-1. Calculation of CUFs for the reactor internals was performed as part of a NSSS design evaluation.

Review of the RPV internals in association with power uprate determined that stresses on the vessel internals remained well below all limits. No recalculation of cumulative usage factors was determined to be required. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

Disposition

The effects of aging on the intended functions of the RPV internals will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

Jet Pump Fatigue Analyses

In August 2000, Columbia operated for a period of time with the recirculation pumps in an unbalanced mode (pump speeds different by more than 50 percent). The effect of that flow imbalance on the jet pumps was an additional accumulation of fatigue usage.

As a result of inspections during the Spring 2001 outage (R-15), a fatigue analysis of the jet pumps was performed and cumulative usage factors were determined.

Jet pump clamps were installed during the 2005 outage (R-17) to minimize flow induced vibration. These clamps greatly reduced the future potential for riser brace fatigue.

As a result of evaluations after the 2007 outage the usage factors were extended to 60 years. The maximum CUF of the jet pump risers for 60 years of operation is projected to remain below the fatigue limit. Columbia manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached. The Fatigue Monitoring Program will also monitor the occurrence of design cycles and will monitor the jet pump gaps, effectively managing the fatigue of the jet pumps through the period of extended operation.

Disposition

The effects of aging on the intended functions of the jet pumps will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.1.3.2.3 Reactor Coolant Pressure Boundary Piping and Piping Component Fatigue Analyses

The Class 1 boundary encompasses all reactor coolant pressure boundary piping (pipe and fittings) and in-line components subject to ASME Section XI, Subsection IWB, inspection requirements. Fatigue analyses of Class 1 piping are based on the transients found in the Columbia piping specifications that are in turn based on the design transients listed in FSAR Section 3.9.

Potential high energy line break (HELB) intermediate locations can be eliminated based on CUFs of less than 0.1 if other stress criteria are also met. The usage factors, as calculated in the design fatigue analyses, account for the design transients assumed for the original 40-year life of the plant. Therefore, the determination of CUFs used in the selection of postulated high energy line intermediate break locations are TLAAs. The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed number of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the associated analyses will be reviewed to determine whether any additional locations need to be designated as postulated HELB locations.

All Class 1 piping was reviewed for the power uprate. The evaluation determined that there was adequate margin in each system to accommodate the power uprate. Design fatigue usage for 40 years of operation and projected fatigue usage for the period of extended operation are established for the limiting reactor coolant pressure boundary components.

A review of documentation found several fatigue analyses for Class 1 valve stress reports found fatigue analyses that were TLAAs. The fatigue usage for those valves is based on transients that are tracked by the Fatigue Monitoring Program.

Metal fatigue for all Class 1 reactor coolant pressure boundary piping and in-line components is managed by the Fatigue Monitoring Program. The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed numbers of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the design calculations for that system will be reviewed and appropriate actions will be taken.

Disposition

The effects of aging on the intended functions of the reactor coolant pressure boundary piping and components will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.1.3.3 Non-Class 1 Component Fatigue Analyses

The non-Class 1 mechanical components susceptible to fatigue fit into one of two major categories: (1) piping and in-line components (piping, valves, tubing, traps, thermowells, etc.) or (2) non-piping components (vessels, heat exchangers, tanks, pumps, etc.).

Non-Class 1 components that are Quality Group B or C are designed and constructed as ASME Section III Code Class 2 and 3, respectively. The design of ASME Class 2 and 3 piping systems incorporates a stress range reduction factor for determining acceptability of piping design with respect to thermal stresses. Non-Class 1 components designated as Quality Class D are designed to ANSI B31.1, which also incorporates stress range reduction factors based upon the number of thermal cycles. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to

7,000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7,000. If fewer than 7,000 cycles are expected through the period of extended operation, then the fatigue analysis (stress range reduction factor) of record will remain valid through the period of extended operation.

Because none of the non-Class 1 vessels, heat exchangers, storage tanks, or pumps were designed to ASME Section VIII, Division 2 or ASME Section III, Subsection NC-3200, no fatigue evaluation is required. Therefore, there are no fatigue TLAAs for these components.

The fatigue evaluation of non-Class 1 piping and in-line components evaluated the associated operating temperature against the threshold temperature value for fatigue of the material. If the threshold temperature value was exceeded, then the number of transient cycles for the piping or in-line component was projected. In each case, the number of projected cycles for 60 years was found to be less than 7,000 for piping and in-line components whose temperatures exceed threshold values. Therefore, fatigue for non-Class 1 piping and in-line components remains valid for the period of extended operation.

Disposition

The TLAA for non-Class 1 component fatigue analyses remains valid for the period of extended operation.

A.1.3.4 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping

Applicants for license renewal are required to address the reactor coolant environmental effects on fatigue of plant components. The minimum set of components for a BWR of Columbia's vintage is derived from NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," as follows:

1. Reactor vessel shell and lower head
2. Reactor vessel feedwater nozzle
3. Reactor recirculation piping (including inlet and outlet nozzles)
4. Core spray line reactor vessel nozzle and associated Class 1 piping
5. Residual heat removal return line Class 1 piping
6. Feedwater line Class 1 piping

Columbia has analyzed these locations for the effects of the reactor coolant environment on fatigue in support of license renewal. Original fatigue usage calculations were reviewed, and the transient groupings and load pairs used in those analyses were carried over to the environmentally-assisted fatigue analyses, with revised non-environmentally assisted usage factors determined.

An effective fatigue life adjustment factor, F_{en}, that considers a time weighted average of operation with normal water chemistry and hydrogen water chemistry over 60 years of operation, was determined for each load pair analyzed for the components at the NUREG/CR-6260 locations. The fatigue life adjustment factors were applied to the revised component load pair usage factors, and the environmentally-adjusted usage factors were summed to obtain environmentally-adjusted CUFs to verify acceptability of the components for the period of extended operation.

Using fatigue data projected by the Fatigue Monitoring Program and the methodology summarized above, the limiting locations (a total of 14 locations corresponding to the six NUREG/CR-6260 components) were evaluated. None of the 14 locations evaluated have an environmentally adjusted CUF of greater than 1.0 during the period of extended operation.

The aging effect of fatigue, including consideration of the environmental effects, will be adequately managed for the period of extended operation using the Fatigue Monitoring Program.

Disposition

The effects of environmentally-assisted fatigue on the intended functions of the limiting NUREG/CR-6260 locations will be adequately managed for the period of extended operation using the Fatigue Monitoring Program.

A.1.3.5 Environmental Qualification of Electrical Equipment

Environmental qualification analyses for electrical equipment are identified as TLAAs. NRC regulation 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," requires licensees to identify electrical equipment covered under this regulation and to maintain a qualification file demonstrating that the equipment is qualified for its application and will perform its safety function up to the end of its qualified life. The EQ Program implements the requirements of 10 CFR 50.49 and will be used to manage the effects of aging on the intended functions of the components associated with environmental qualification TLAAs for the period of extended operation.

Disposition

The effects of aging on the intended functions of the environmentally qualified components will be adequately managed for the period of extended operation by the EQ Program.

A.1.3.6 Fatigue of Primary Containment, Attached Piping, and Components

The Primary Containment and attached piping and components susceptible to fatigue resulting from the effects of plant transients are evaluated below.

A.1.3.6.1 Primary Containment

The cycles used in the fatigue evaluation of the containment components are provided in FSAR Table 3A.4.1-3. No operating basis earthquakes have been experienced by Columbia through 2007, and the containment analysis for five operating basis earthquakes remains valid for 60 years of plant operation. The safe shutdown earthquake and post-loss of coolant accident (LOCA) chugging are once in a lifetime events and are not projected to occur during the extended period of operation. Safety relief valve actuations have been projected through 60 years of operation based on the number of actual events through 2007. The fatigue analyses performed using these events will remain valid for the period of extended operation.

As the cycles on which the containment fatigue analysis is based will not be exceeded for 60 years of operation, these analyses will remain valid for the period of extended operation.

Disposition

The TLAA associated with fatigue of the containment remains valid for the period of extended operation.

A.1.3.6.2 ASME Class MC Components

Class MC components include the primary containment vessel shell, large openings (equipment hatch, personnel hatches, and access hatch), penetrations (all except the large openings), and attachments (pipe supports in the wetwell, welding pads in the drywell, supports for the stabilizer truss, seal and shear lugs at the drywell floor, supports for the downcomer bracing system, pipe whip supports, radial beam supports, cap truss supports, catwalks, monorail, and platforms). The Class MC components were analyzed for fatigue using the transients listed in FSAR Table 3A.4.1-3. As these cycles will not be exceeded for 60 years of operation, the Class MC component fatigue analysis will remain valid for the period of extended operation.

A specific fatigue analysis was performed for the main steam penetrations using the transients listed in FSAR Table 3A.4.1-3. This analysis will remain valid for the period of extended operation as these cycles will not be exceeded for 60 years of operation.

The effects of power uprate on the containment system response were reviewed and determined to be negligible. The containment peak pressure values remain virtually unaffected by the power uprate and extended load line limit. The LOCA containment dynamic loads are not affected by power uprate, and safety relief valve containment loads will remain below their design allowables. (see FSAR Appendix 3A)

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the Class MC containment components remains valid for the period of extended operation.

Disposition

The TLAAs for fatigue of the ASME Class MC components remain valid through the end of the period of extended operation.

A.1.3.6.3 Downcomers

Although not an ASME Code requirement, a fatigue evaluation of the downcomers was performed. The fatigue evaluation of the downcomer lines in the wetwell air volume was based on the number of cycles presented in FSAR Table 3A.4.1-3. The maximum fatigue usage factor for the downcomers is provided in FSAR Table 3A.4.2-4 and FSAR Table 3A.4.2-5.

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the downcomers remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the downcomers remains valid through the end of the period of extended operation.

A.1.3.6.4 Safety Relief Valve Discharge Piping

Although not an ASME Code requirement, a fatigue evaluation of the safety relief valve (SRV) discharge piping was performed. The fatigue evaluation used the number of cycles as presented in FSAR Table 3A.4.1-3. The maximum fatigue usage factor for all 18 SRV discharge lines in the wetwell air volume is below the ASME allowable limits per FSAR Section 3A.4.2.4.6.

The SRV actuations for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the SRV discharge piping remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the SRV discharge piping remains valid through the end of the period of extended operation.

A.1.3.6.5 Diaphragm Floor Seal

The diaphragm floor seal is located at the inside surface of the primary containment vessel periphery. It provides a flexible, pressure tight seal between the primary containment vessel and the diaphragm floor and is capable of accommodating differential thermal expansion between them.

The fatigue evaluation was performed using the cycles in FSAR Table 3A.4.1-3. The maximum cumulative usage factor is less than the fatigue limit per FSAR Table 3A.4.1-5. All events, including SRV actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the diaphragm floor seal remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the containment diaphragm floor seal remains valid through the end of the period of extended operation.

A.1.3.6.6 ECCS Suction Strainers

The original Columbia ECCS suction strainers were replaced with a new strainer design constructed from cold-worked austenitic stainless steel. A linear elastic fracture mechanics analysis was performed to bound all the martensitic material in the suction strainer screens. A crack depth was assumed based on the depth of the Alpha Prime martensite in the strainer screen material.

Cyclic stresses were considered in the crack growth analysis of the suction strainers. The fatigue crack evaluation determined that the assumed cracks will not propagate to a critical size for the remaining life of the plant. The maximum computed stress intensity value (K) was less than that required to cause cracking in Alpha martensite formed in austenitic stainless steel.

The stress value conservatively included direct pressure and inertial components from SRV actuation, operating basis earthquake (OBE) loads, and SRV steam chugging. (See FSAR Table 3A.4.1-3.)

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the ECCS suction strainers remains valid for the period of extended operation.

Disposition

The TLAA for crack growth of the ECCS suction strainers remains valid through the end of the period of extended operation.

A.1.3.7 Other Plant-Specific Time-Limited Aging Analyses

The TLAAs that do not fit into any of the previous major categories are evaluated below.

A.1.3.7.1 Reactor Vessel Shell Indications

Two indications in the reactor vessel shell were identified using ultrasonic inspection methods during the 2005 inservice inspections. The indications were present in past inservice inspection examinations, but became rejectable under current ASME Section XI, IWB-3610 requirements. The rejected indications were evaluated and determined to be acceptable for continued service without repair, as reported to the NRC. The indications were evaluated per the guidelines of ASME Section XI, IWB-3610, which include acceptance criteria based on the applied stress intensity factors, using conservative assumptions in the applied stresses to determine the stress intensity factors for comparison to Code allowables.

This conservative evaluation calculated a fatigue crack growth at the end of 33.1 EFPY vessel service life that is insignificant in comparison to the bounding initial crack size. It also determined that the applied stress intensity factor is well below the allowable stress intensity factor.

The calculation is based on time-limited assumptions of neutron fluence and SRV blowdown cycles for 40 years. While it is not expected that the applied stress intensity factor will exceed the allowable fracture toughness during the period of extended operation, cracking near the subject reactor vessel welds is managed by the Inservice Inspection (ISI) Program.

<u>Disposition</u>

Cracking of the reactor vessel shell near welds BG and BM will be adequately managed through the period of extended operation by the Inservice Inspection (ISI) Program.

A.1.3.7.2 Sacrificial Shield Wall

FSAR Section 3.8.3.6 provides a value of neutron fluence for the outside face of the sacrificial shield wall that is based on 40 years of plant operation. Projections done for 60 years of operation, including increase in fluence due to power uprate, determined that the estimated neutron fluence on the sacrificial shield wall will remain below the threshold for neutron damage of concrete and reinforcing steel. Therefore, the sacrificial shield wall can be expected to perform its radiation shielding function through the period of extended operation.

<u>Disposition</u>

The TLAA associated with the sacrificial shield wall fluence has been projected to the end of the period of extended operation.

A.1.3.7.3 Main Steam Flow Restrictor Erosion Analyses

The main steam line flow restrictors are designed to limit coolant flow rate from the reactor vessel (before the MSIVs are closed) to less than 200 percent of normal flow in the event of a main steam line break outside the containment. Erosion of a flow restrictor is a safety concern since it could impair the ability of the flow restrictor to limit vessel blowdown following a main steam line break. Since erosion is a time-related phenomenon, the analysis for the effect it has on the flow restrictors over the life of the plant is a TLAA. Cast stainless steel (SA351, Type CF8) was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion from high velocity steam.

The erosion of the main steam flow restrictors has been projected for the period of extended operation. The projection concludes that after 60 years of erosion on the main steam flow restrictors, the choked flow will still be less than 200 percent of normal flow. Therefore, the main steam flow restrictors will continue to perform their intended function and the existing accident radiological release analysis will remain valid for the period of extended operation.

Disposition

The TLAA for erosion of the main steam line flow restrictors has been projected to the end of the period of extended operation.

A.1.4 References

A.1.4-1 BWROG Report GE-NE-523-A71-0594-A, Rev 1, "Alternate BWR Feedwater Nozzle Inspection Requirements," May 2000

A.1.4-2 EPRI Report No. 1011838, "Recommendations for An Effective Flow Accelerated Corrosion Program (NSAC-202L-R3)," May 2006

A.1.5 License Renewal Commitment List

A listing of commitments identified in association with Columbia license renewal is provided in Table A-1. These commitments will be tracked within the Columbia regulatory commitment management program. Any other actions discussed in the LRA represent intended or planned actions. They are described to the NRC for information and are not regulatory commitments.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
1) Aboveground Steel Tanks Inspection	The Aboveground Steel Tanks Inspection is a new activity. The Aboveground Steel Tanks Inspection detects and characterizes the conditions on the bottom surfaces of the condensate storage tanks. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred in inaccessible areas.	A.1.2.1	Within the 10-year period prior to the period of extended operation.
2) Air Quality Sampling Program	The Air Quality Sampling Program is an existing program that will be continued for the period of extended operation.	A.1.2.2	Ongoing
3) Appendix J Program	The Appendix J Program is an existing program that will be continued for the period of extended operation.	A.1.2.3	Ongoing
4) Bolting Integrity Program	The Bolting Integrity Program is an existing program that will be continued for the period of extended operation.	A.1.2.4	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
5) Buried Piping and Tanks Inspection Program	The Buried Piping and Tanks Inspection Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Revise the site program document to include the buried portions of the Radwaste Building Outside Air (WOA) piping. • Require that an inspection of a representative sample of buried piping be performed within the 10-year period prior to entering the period of extended operation (i.e., between year 30 and year 40). • Require an additional inspection of a representative sample of buried piping be performed within 10 years after entering the period of extended operation (i.e., between year 40 and year 50).	A.1.2.5	Enhancement prior to the period of extended operation. Then ongoing.
6) BWR Feedwater Nozzle Program	The BWR Feedwater Nozzle Program is an existing program that will be continued for the period of extended operation.	A.1.2.6	Ongoing
7) BWR Penetrations Program	The BWR Penetrations Program is an existing program that will be continued for the period of extended operation.	A.1.2.7	Ongoing
8) BWR Stress Corrosion Cracking Program	The BWR Stress Corrosion Cracking Program is an existing program that will be continued for the period of extended operation.	A.1.2.8	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
9) BWR Vessel ID Attachment Welds Program	The BWR Vessel ID Attachment Welds Program is an existing program that will be continued for the period of extended operation.	A.1.2.9	Ongoing
10) BWR Vessel Internals Program	The BWR Vessel Internals Program is an existing program that will be continued for the period of extended operation.	A.1.2.10	Ongoing
11) BWR Water Chemistry Program	The BWR Water Chemistry Program is an existing program that will be continued for the period of extended operation.	A.1.2.11	Ongoing
12) Chemistry Program Effectiveness Inspection	The Chemistry Program Effectiveness Inspection is a new activity. The Chemistry Program Effectiveness Inspection detects and characterizes the condition of materials in representative low flow and stagnant areas of systems with water chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program, and with fuel oil chemistry controlled by the Fuel Oil Chemistry Program . The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.12	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
13) Closed Cooling Water Chemistry Program	The Closed Cooling Water Chemistry Program is an existing program that will be continued for the period of extended operation, with the following enhancement: • Ensure that at least one additional Reactor Closed Cooling Water corrosion rate measurement is performed and evaluated prior to entering the period of extended operation to provide direct information as to the effectiveness of the chemical treatments. If necessary, based on the results, establish a frequency for subsequent measurements.	A.1.2.13	Enhancement prior to the period of extended operation. Then ongoing.
14) Cooling Units Inspection	The Cooling Units Inspection is a new activity. The Cooling Units Inspection detects and characterizes the material condition of cooling unit components that are exposed to condensation. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.14	Within the 10-year period prior to the period of extended operation.
15) CRDRL Nozzle Program	The CRDRL Nozzle Program is an existing program that will be continued for the period of extended operation.	A.1.2.15	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
16) Diesel Starting Air Inspection	The Diesel Starting Air Inspection is a new activity. The Diesel Starting Air Inspection detects and characterizes the condition of materials for the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers). The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.16	Within the 10-year period prior to the period of extended operation.
17) Diesel Systems Inspection	The Diesel Systems Inspection is a new activity. The Diesel Systems Inspection detects and characterizes the condition of materials for the interior of the exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping, and the drain pans and drain piping associated with air-handling units of the Diesel Building HVAC systems. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.17	Within the 10-year period prior to the period of extended operation.
18) Diesel-Driven Fire Pumps Inspection	The Diesel-Driven Fire Pumps Inspection is a new activity. The Diesel-Driven Fire Pumps Inspection detects and characterizes the material condition of the interior of the Fire Protection System diesel engine exhaust piping, and of Fire Protection System diesel heat exchangers exposed to a raw water environment. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.18	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
19) Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new program. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is an inspection program that detects degradation of electrical cables and connections that are not environmentally qualified and are within the scope of license renewal. The program provides for the periodic visual inspection of accessible, non-environmentally qualified cables and connections in order to determine if age-related degradation is occurring, particularly in plant areas with adverse localized environments.	A.1.2.19	Implementation prior to the period of extended operation. Then ongoing.
20) Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new program. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a monitoring program that detects degradation of electrical cables and connections that are not environmentally qualified and used in circuits with sensitive, low-current applications. The program provides for a review of calibration records for low-current instruments, in order to detect and identify degradation of the cable system insulation resistance. The program retains the option to perform direct cable testing.	A.1.2.20	Implementation prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
21) Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection	The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new activity. The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection detects and characterizes the material condition of metallic electrical connections within the scope of license renewal. The inspection uses thermography (augmented by contact resistance testing) to detect loose or degraded connections that lead to increased resistance for a representative sample of metallic electrical connections in various plant locations.	A.1.2.21	Within the 10-year period prior to the period of extended operation.
22) EQ Program	The EQ Program is an existing program that will be continued for the period of extended operation.	A.1.2.22 A.1.3.5	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
23) External Surfaces Monitoring Program	The External Surfaces Monitoring Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Add aluminum, copper alloy, copper alloy >15 % Zn, gray cast iron, stainless steel (including CASS), and elastomers to the scope of the program. • Add cracking as an aging effect for aluminum and stainless steel components. • Add visual (VT-1 or equivalent) or volumetric examination techniques to detect cracking. • Add hardening and loss of strength as aging effects for elastomer-based mechanical sealants and flexible connections in HVAC systems. • Add physical examination techniques in addition to visual inspection to detect hardening and loss of strength for elastomer-based mechanical sealants and flexible connections in HVAC systems.	A.1.2.23	Enhancement prior to the period of extended operation. Then ongoing.
24) Fatigue Monitoring Program	The Fatigue Monitoring Program is an existing program that will be continued for the period of extended operation, with the following enhancements:	A.1.2.24 A.1.3.2 A.1.3.4	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
24) Fatigue Monitoring Program (cont'd)	• Columbia has analyzed the effects of the reactor coolant environment on fatigue for the six locations recommended by NUREG\CR-6260. These analyses are based on the projected cycles for 60 years of operation (plus some conservatism) rather than the original design cycles in FSAR Table 3.9-1. The Fatigue Monitoring Program will be enhanced to ensure that action will be taken when the lowest number of analyzed cycles is approached. • For each location that may exceed a CUF of 1.0 (due to projected cycles exceeding analyzed, or due to as-yet undiscovered industry issues), the Fatigue Monitoring Program will implement one or more of the following: (1) Refine the fatigue analyses to determine valid CUFs less than 1.0, (2) Manage the effects of aging due to fatigue at the affected locations by an inspection program that has been reviewed and approved by the NRC, or (3) Repair or replace the affected locations before exceeding a CUF of 1.0. • Correlate information relative to fatigue monitoring and provide more definitive verification that the transients monitored and their limits are consistent with or bound the FSAR and the supporting fatigue analyses, including the environmentally-assisted fatigue analyses.		

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
25) Fire Protection Program	The Fire Protection Program is an existing program that will be continued for the period of extended operation.	A.1.2.25	Ongoing
26) Fire Water Program	The Fire Water Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Perform either ultrasonic testing or internal visual inspection of representative portions of above ground fire protection piping that are exposed to water, but do not normally experience flow, after the issuance of the renewed license, but prior to the end of the current operating term and at reasonable intervals thereafter, based on engineering review of the results. • Either replace sprinkler heads that have been in place for 50 years or submit representative samples to a recognized laboratory for field service testing in accordance with NFPA 25 recommendations. Perform subsequent replacement or field service testing of representative samples at 10-year intervals thereafter or until there are no sprinkler heads installed that will reach 50 years of service life during the period of extended operation. • Perform hardness testing (or equivalent) of the sprinkler heads as part of their NFPA sampling, to determine whether loss of material due to selective leaching is occurring.	A.1.2.26	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
27) Flexible Connection Inspection	The Flexible Connection Inspection is a new activity. The Flexible Connection Inspection detects and characterizes the material condition of elastomer components exposed to treated water, dried air, gas, and indoor air environments. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.27	Within the 10-year period prior to the period of extended operation.
28) Flow-Accelerated Corrosion (FAC) Program	The Flow-Accelerated Corrosion (FAC) Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Add the Containment Nitrogen System components supplied with steam from the Auxiliary Steam System to the scope of the program. • Add gray cast iron as a material identified as susceptible to FAC.	A.1.2.28	Enhancement prior to the period of extended operation. Then ongoing.
29) Fuel Oil Chemistry Program	The Fuel Oil Chemistry Program is an existing program that will be continued for the period of extended operation.	A.1.2.29	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
30) Heat Exchangers Inspection	The Heat Exchangers Inspection is a new activity. The Heat Exchangers Inspection detects and characterizes the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to treated water, closed cooling water, or indoor air. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.30	Within the 10-year period prior to the period of extended operation.
31) High-Voltage Porcelain Insulators Aging Management Program	The High-Voltage Porcelain Insulators Aging Management Program is an existing program that will be continued for the period of extended operation.	A.1.2.31	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
32) Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program	The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new program. The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program manages the aging of inaccessible medium-voltage cables that are not environmentally qualified and are within the scope of license renewal. The program provides for testing to identify the conditions of the conductor insulation, and also provides for periodic inspection and drainage (if necessary) of electrical manholes. The frequency of the cable testing portion of the program will be once every 10 years, with the first test to be performed prior to the period of extended operation. The frequency of the manhole inspections will be at least once every two years, with the first inspections to be performed prior to the period of extended operation.	A.1.2.32	Implementation prior to the period of extended operation. Then ongoing.
33) Inservice Inspection (ISI) Program	The Inservice Inspection (ISI) Program is an existing program that will be continued for the period of extended operation.	A.1.2.33	Ongoing
34) Inservice Inspection (ISI) Program – IWE	The Inservice Inspection (ISI) Program – IWE is an existing program that will be continued for the period of extended operation.	A.1.2.34	Ongoing
35) Inservice Inspection (ISI) Program – IWF	The Inservice Inspection (ISI) Program - IWF is an existing program that will be continued for the period of extended operation.	A.1.2.35	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
36) Lubricating Oil Analysis Program	The Lubricating Oil Analysis Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Include the following Fire Protection System components that are exposed to lubricating oil within the scope of the program: (1) fire protection diesel engine heat exchangers (lube oil coolers), (2) fire protection diesel engine lube oil piping, and (3) fire protection diesel engine lube oil pump casings.	A.1.2.36	Enhancement prior to the period of extended operation. Then ongoing.
37) Lubricating Oil Inspection	The Lubricating Oil Inspection is a new activity. The Lubricating Oil Inspection detects and characterizes the condition of materials in systems and components for which the Lubricating Oil Analysis Program is credited with aging management. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.37	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
38) Masonry Wall Inspection	The Masonry Wall Inspection is an existing program that will be continued for the period of extended operation, with the following enhancements: • Specify that for each masonry wall, the extent of observed masonry cracking or degradation of steel edge supports and bracing are evaluated to ensure that the current evaluation basis is still valid. Corrective action is required if the extent of masonry cracking or steel degradation is sufficient to invalidate the evaluation basis. An option is to develop a new evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation).	A.1.2.38	Enhancement prior to the period of extended operation. Then going.
39) Material Handling System Inspection Program	The Material Handling System Inspection Program is an existing program that will be continued for the period of extended operation, with the following enhancement: • Ensure jib cranes and electrically operated hoists are visually inspected for corrosion.	A.1.2.39	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
40) Metal-Enclosed Bus Program	The Metal-Enclosed Bus Program is a new program. The Metal-Enclosed Bus Program is an inspection program that detects degradation of metal-enclosed bus within the scope of license renewal. The program provides for the visual inspection of interior sections of bus, and an inspection of the elastomeric seals at the joints of the duct sections. The program also makes provision for thermographic inspection of bus bolted connections. The thermography portion of the program will be performed once every 10 years, with the initial inspections to be performed prior to the period of extended operation. The visual inspection portion of the program will also be performed once every 10 years, with the first inspections to be performed prior to the period of extended operation.	A.1.2.40	Implementation prior to the period of extended operation. Then ongoing.
41) Monitoring and Collection Systems Inspection	The Monitoring and Collection Systems Inspection is a new activity. The Monitoring and Collection Systems Inspection detects and characterizes the condition of materials at the internal surfaces of subject mechanical components that are exposed to equipment or area drainage water and other potential contaminants and fluids. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.41	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
42) Open-Cycle Cooling Water Program	The Open-Cycle Cooling Water Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Address loss of material due to cavitation erosion (for the Standby Service Water (SW), Circulating Water (CW), Plant Service Water (TSW), and Tower Make-Up (TMU) systems) with activities such as opportunistic inspections of portions of the systems that have had indications of cavitation erosion in the past. • Include the non-safety related components within the license renewal scope in the SW, CW, TSW, and TMU systems, and the non-safety related components served by or connected to the TSW System that are in the Process Sampling, Process Sampling Radioactive, Radwaste Building Mixed Air, Radwaste Building Return Air, Reactor Building Return Air, and Reactor Closed Cooling Water systems.	A.1.2.42	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
43) Potable Water Monitoring Program	The Potable Water Monitoring Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Include periodic inspection activities. Based on operating experience, it is necessary that inspections be conducted at least once every five years, and include components of the Potable Cold Water and Potable Hot Water systems that are located in the Reactor Building, and components associated with the Reactor Building Outside Air (ROA) air washer (ROA-AW-1), including the air washer housing. At least one inspection will be conducted within the 10-year period prior to the period of extended operation.	A.1.2.43	Enhancement and inspection within the 10-year period prior to the period of extended operation. Then ongoing.
44) Preventive Maintenance – RCIC Turbine Casing	The Preventive Maintenance – RCIC Turbine Casing is an existing program that will be continued for the period of extended operation.	A.1.2.44	Ongoing
45) Reactor Head Closure Studs Program	The Reactor Head Closure Studs Program is an existing program that will be continued for the period of extended operation.	A.1.2.45	Ongoing
46) Reactor Vessel Surveillance Program	The Reactor Vessel Surveillance Program is an existing program that will be continued for the period of extended operation.	A.1.2.46	Ongoing

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
47) Selective Leaching Inspection	The Selective Leaching Inspection is a new activity. The Selective Leaching Inspection detects and characterizes the conditions on internal and external surfaces of subject components exposed to raw water, treated water, fuel oil, soil, and moist air (including condensation) environments. The inspection provides direct evidence through a combination of visual examination and hardness testing, or NRC-approved alternative, as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.47	Within the 10-year period prior to the period of extended operation.
48) Service Air System Inspection	The Service Air System Inspection is a new activity. The Service Air System Inspection detects and characterizes the material condition of steel piping and valve bodies exposed to an "air (internal)" (i.e., compressed air) environment within the license renewal boundary of the Service Air System. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.48	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
49) Small Bore Class 1 Piping Inspection	The Small Bore Class 1 Piping Inspection is a new activity. The Small Bore Class 1 Piping Inspection will detect and characterize the conditions on the internal surfaces of small bore Class 1 piping components that are exposed to reactor coolant. The Small Bore Class 1 Piping Inspection will provide physical evidence as to whether, and to what extent, the relevant effects of aging have occurred. The Small Bore Class 1 Piping Inspection includes visual and volumetric inspection of a representative sample of small bore Class 1 piping components. The inspection provides additional assurance that cracking of small bore Class 1 piping is not occurring or is insignificant, such that an aging management program is not warranted during the period of extended operation. This one-time inspection is appropriate as Columbia has not experienced cracking of small bore Class 1 piping from stress corrosion or thermal and mechanical loading. Should evidence of significant aging be revealed by the one-time inspection or through plant operating experience, periodic inspection will be considered as a plant-specific aging management program.	A.1.2.49	Within the portion of the fourth 10-year ISI interval that occurs prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
50) Structures Monitoring Program	The Structures Monitoring Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Include and list the structures within the scope of license renewal that credit the Structures Monitoring Program for aging management. • Specify that if a below grade structural wall or structural component becomes accessible through excavation; a follow-up action is initiated for the responsible engineer to inspect the exposed surfaces for age-related degradation prior to backfilling. • Identify that the term "structural component" for inspection includes component types that credit the Structures Monitoring Program for aging management. • Include the potential degradation mechanism checklist in the procedural documents. The checklist also requires enhancement to include aging effect terminology (e.g., loss of material, cracking, change in material properties, and loss of form).	A.1.2.50	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
50) Structures Monitoring Program (cont'd)	• Specify that the responsible engineer shall review site groundwater and raw water testing results for pH, chlorides, and sulfates prior to inspection to validate that the below-grade or raw water environments remain non-aggressive during the period of extended operation. Chemistry data shall be obtained from Columbia's chemistry and environmental departments. Groundwater chemistry data shall be collected at least once every four years. The time of data collection shall be staggered from year to year (summer-winter-summer) to account for seasonal variations in the environment.		
51) Supplemental Piping/Tank Inspection	The Supplemental Piping/Tank Inspection is a new activity. The Supplemental Piping/Tank Inspection detects and characterizes the material condition of steel, gray cast iron, and stainless steel components exposed to moist air environments. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.51	Within the 10-year period prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
52) Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program	The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program. The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals. The program includes: (a) identification of susceptible components determined to be limiting from the standpoint of thermal aging or neutron irradiation embrittlement (neutron fluence), (b) a component-specific evaluation to determine each identified component's susceptibility to loss of fracture toughness, and (c) a supplemental examination of any component not eliminated by the component-specific evaluation.	A.1.2.52	Implementation prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
53) Water Control Structures Inspection	The Water Control Structures Inspection is an existing program that will be continued for the period of extended operation, with the following enhancements: • Include and list the water control structures within the scope of license renewal. Include the RG 1.127 Revision 1 inspection elements for the water control structures, including submerged surfaces. Ensure descriptions of concrete conditions conform with the appendix to the American Concrete Institute (ACI) publication, ACI 201, "Guide for Making a Condition Survey of Concrete in Service." Add a recommendation to use photographs for comparison of previous and present conditions. Add a requirement for the documentation of new or progressive problems as a part of the inspection program.	A.1.2.53	Enhancement prior to the period of extended operation. Then ongoing.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
54) Pressure-Temperature Limits	The Columbia P-T limit curves were revised in 2005 to include the effects of power uprate to 3486 MWt. The P-T limits are valid for 33.1 EFPY through the end of the currently licensed period. P-T limits for the period of extended operation will be calculated using the most accurate fluence projections available at the time of the recalculation. The projections may be adjusted if there are changes in core design or if additional surveillance capsule results show the need for an adjustment. The projected ART for the period of extended operation gives confidence that future P-T curves will provide adequate operating margin. License amendment requests to revise the P-T limits will be submitted to the NRC for approval, when necessary to comply with 10 CFR 50 Appendix G, as part of the Reactor Vessel Surveillance Program.	A.1.3.1.4	Ongoing
55) Incorporate FSAR Supplement	Energy Northwest will incorporate the FSAR Supplement into the Columbia FSAR as required by 10 CFR 54.21(d).	A.1 A.1.1	Following issuance of the renewed operating license.
56) Operational Quality Assurance Program Description	The elements of corrective actions, confirmation process, and administrative controls in the OQAPD will be applied to required aging management programs for both safety-related and non-safety related structures and components determined to require aging management during the period of extended operation.	A.1.2	Prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
57) License Renewal Commitment List	The commitments identified in association with Columbia license renewal will be tracked within the Columbia regulatory commitment management program.	A.1.5	Upon submittal of the license renewal application to the NRC.
58) BWRVIP-42-A, AAI#5	In accordance with the BWR Vessel Internals Program, Columbia will implement the additional inspection requirements of BWRVIP-42-A once those requirements are approved by the NRC staff.	LRA Appendix C	Based on NRC schedule.
59) BWRVIP-116	Energy Northwest will submit a licensing basis change request to implement the BWRVIP ISP(E) at least two years prior to the period of extended operation. Columbia will implement the ISP(E) as amended by the BWRVIP letter of January 11, 2005, including the new capsule test schedule in Table 1 of that letter.	LRA Appendix C	Two years prior to the period of extended operation.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
60) BWRVIP-116	Implementation of the BWRVIP ISP(E) for Columbia will include the following details in support of the contingency plan: (1) Energy Northwest will include the requirement to keep all tested material (irradiated or unirradiated) for possible future reconstitution and testing. (2) The Columbia site procedure, as modified, will continue to require any capsules removed from the reactor vessel to be stored in a manner that would support future re-insertion of these capsules in the reactor vessel. (3) Energy Northwest will notify the BWRVIP prior to any change in the storage of on-site materials. NRC approval will be obtained prior to any change in the storage of surveillance materials that would affect the potential use of the materials under the contingency plan.	LRA Appendix C	On-going

APPENDIX B

AGING MANAGEMENT PROGRAMS

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B.0 AGING MANAGEMENT PROGRAMS

B.1 INTRODUCTION

B.1.1 Overview

License renewal aging management program descriptions are provided in this appendix for each program credited for managing aging effects based upon the aging management review results provided in Sections 3.1 through 3.6 of this Application.

Each aging management program described in this appendix is evaluated on the basis of 10 program elements in accordance with the guidance in Appendix A.1, Section A.1.2.3 of NUREG-1800, the Standard Review Plan for License Renewal (SRP-LR).

B.1.2 Method of Discussion

For those existing AMPs that are comparable to the programs described in Sections X and XI of NUREG-1801, the "Generic Aging Lessons Learned (GALL) Report," the program evaluation is presented in the following summary format:

- **Program Description** – An abstract of the overall program is provided.
- **NUREG-1801 Consistency** – A statement is made regarding consistency between the Columbia program and the corresponding NUREG-1801 program.
- **Exceptions to NUREG-1801** – Exceptions to NUREG-1801 programs are identified when elements of the Columbia program are different from the NUREG-1801 program elements or when elements of the NUREG-1801 program are not applicable to Columbia. Each exception is listed along with the affected element. A justification is provided for each exception.
- **Required Enhancements** – Enhancements to existing programs necessary to ensure consistency with NUREG-1801 or to expand the scope of the program for license renewal are identified. Each enhancement is listed along with the affected program element and a proposed schedule for completion of the enhancement.
- **Operating Experience** – Discussion of operating experience information specific to the program is provided.
- **Conclusion** – A conclusion section provides a statement of reasonable assurance that the program is effective, or will be effective, once enhanced or developed.

For those programs that are either new or plant-specific, the above format is followed along with the additional provision of a discussion of each of the 10 elements associated with the program.

B.1.3 Quality Assurance Program and Administrative Controls

Three elements of an effective aging management program that are common to each of the aging management programs are corrective actions, confirmation process, and administrative controls. These elements are included in the Operational Quality Assurance Program Description (OQAPD) for Columbia, which implements the requirements of 10 CFR 50 Appendix B. The OQAPD is described in FSAR Sections 3.1.2.1.1, 13.4, and 17.2.

Prior to the period of extended operation, the elements of corrective actions, confirmation process, and administrative controls in the OQAPD will be applied to required aging management programs for both safety-related and NSR structures and components determined to require aging management during the period of extended operation. The corrective actions, confirmation process, and administrative controls in the OQAPD, to be applied to the credited aging management programs and activities for the structures and components determined to require aging management, are consistent with the related discussions in the Appendix on Quality Assurance for Aging Management Programs in NUREG-1801, Volume 2.

The elements of corrective actions, confirmation process, and administrative controls of the OQAPD are described in the sections below, including a general comparison to the associated elements of the corresponding NUREG-1801 aging management programs (AMPs), which indicate that the "staff finds the requirements of 10 CFR Part 50, Appendix B acceptable to address the corrective actions (and confirmation process)."

Corrective Actions:

Corrective actions are implemented through the site corrective action program, which includes the initiation, processing, and evaluation of condition reports, that satisfies the requirements of 10 CFR 50, Appendix B, Criterion XVI. Conditions adverse to quality, an all inclusive term used in reference to failures, malfunctions, deficiencies, defective items, and non-conformances are identified, reported to management, and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the root cause is determined and that corrective actions are taken to preclude recurrence.

The corrective action program is the subject of periodic NRC examination and Columbia self-assessment and audit. In general, problems are effectively identified, evaluated and prioritized, and effective corrective actions implemented for conditions adverse to quality. Some program shortfalls have been identified, but corresponding process improvement plans have been developed and implemented. The current program is, therefore, adequate for aging management considerations.

Confirmation Process:

The focus of the confirmation process is on the follow-up actions taken to verify effective implementation of corrective actions and preclude repetition of significant conditions adverse to quality. The corrective action program includes the requirement that measures be taken to preclude repetition of significant conditions adverse to quality. These measures include actions to verify effective implementation of proposed corrective actions. The confirmation process is part of the corrective action program and, for significant conditions adverse to quality, includes:

- reviews to assure proposed actions are adequate,
- tracking and reporting of open corrective actions,
- Root Cause and Apparent-Common Cause evaluations, and
- reviews of corrective action effectiveness.

Effectiveness reviews are conducted as part of the corrective action process to ensure that all corrective actions have been completed and to identify any repetition of the event. The corrective action process is also monitored for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of a follow-up condition report.

Administrative Controls:

Administrative controls that govern aging management activities are established within the document control procedures that implement: (1) industry standards related to administrative controls and quality assurance for the operational phase of nuclear power plants, and (2) the requirements of 10 CFR 50, Appendix B, Criterion VI.

Plant policies, directives, and procedures are written and controlled to specify and manage various activities, particularly those related to compliance with 10 CFR 50, Appendix B. The phrase "administrative control" refers to the adherence to the policies, directives, and procedures, and includes the formal review and approval process that the plant policies, directives, and procedures undergo as they are issued (and subsequently revised). The individual documents (i.e., the plant policies, directives, and procedures), in conjunction with the plant's quality assurance program documents, provide the overall administrative framework to ensure regulatory requirements are met.

B.1.4 Operating Experience

Operating experience for existing Columbia plant programs and activities was reviewed as an input to the aging management program evaluations. The operating experience review demonstrates the effectiveness of the plant programs and activities that are credited with aging management for the period of extended operation.

Plant procedures require that the discovery of conditions adverse to quality be documented in accordance with the corrective action program. A review of plant records for the most recent seven-year period (January 2001 through July 2008) was performed in order to identify age-related issues of degradation related to current plant operation. The scope of the review included reports generated under the corrective action program and licensee event reports. These records provide documentation of situations where systems, structures, and components exhibit conditions adverse to quality, including age-related degradation. Keywords related to aging and degradation were used to search the records.

The operating experience review provides the basis for the determination that existing programs are either effective or require enhancement; that one-time inspections are appropriate to verify that either aging is not occurring or that aging is being effectively managed by an existing program; or that a new program is required to be established to manage the effects of aging.

The operating experience review included consideration of the results of programmatic assessments performed by Columbia and of those performed by outside agencies, including the NRC. Past corrective actions resulting in program enhancements are included in the evaluation of program effectiveness. Industry operating experience was considered specifically for new programs with no plant-specific operating experience or when industry events were significant for existing programs. The operating experience review provides objective evidence that the effects of aging will be managed for the period of extended operation.

B.1.5 Aging Management Programs

Table B-1 provides a listing of the NUREG-1801 aging management programs and the corresponding aging management programs for Columbia. Table B-2 provides a summary of the aging management programs for Columbia with respect to consistency with NUREG-1801 aging management programs. Table B-2 also provides information on whether programs are existing or new, whether enhancements are required, and whether the programs are plant-specific. Each aging management program credited for license renewal is addressed in Section B.2.

B.2 AGING MANAGEMENT PROGRAMS

The correlation between NUREG-1801 programs and Columbia aging management programs is shown in the following table. The table is organized by the NUREG-1801 program number, first for Chapter XI, then for Chapter X, and finally for plant-specific programs.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs

Number	NUREG-1801 Program	Corresponding Columbia AMP
NUREG-1801 Chapter XI		
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Inservice Inspection (ISI) Program See Section B.2.33.
XI.M2	Water Chemistry	BWR Water Chemistry Program See Section B.2.11.
XI.M3	Reactor Head Closure Studs	Reactor Head Closure Studs Program See Section B.2.45.
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds Program See Section B.2.9.
XI.M5	BWR Feedwater Nozzle	BWR Feedwater Nozzle Program See Section B.2.6.
XI.M6	BWR Control Rod Drive Return Line Nozzle	CRDRL Nozzle Program See Section B.2.15.
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking Program See Section B.2.8.
XI.M8	BWR Penetrations	BWR Penetrations Program See Section B.2.7.
XI.M9	BWR Vessel Internals	BWR Vessel Internals Program See Section B.2.10.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.M10	Boric Acid Corrosion	Not Applicable. Columbia is a BWR and does not use boric acid in any systems. The Standby Liquid Control System uses a sodium pentaborate solution (a mixture of boric acid and borax) that is not aggressive to metals.
XI.M11A	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Not Applicable. This program is applicable to PWR plants, Columbia is a BWR.
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Not credited for aging management. The Inservice Inspection (ISI) Program (See Section B.2.33) or the Small Bore Class 1 Piping Inspection (See Section B.2.49) is credited for pump casings and valve bodies.
XI.M13	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program See Section B.2.52.
XI.M14	Loose Parts Monitoring	Not credited for aging management. The Columbia loose parts detection system has been deactivated and spared in-place, as described in FSAR Section 7.7.1.12.
XI.M15	Neutron Noise Monitoring	Not Applicable. This program is applicable to PWR plants, Columbia is a BWR.
XI.M16	PWR Vessel Internals	Not Applicable. This program is applicable to PWR plants, Columbia is a BWR.
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (FAC) Program See Section B.2.28.
XI.M18	Bolting Integrity	Bolting Integrity Program See Section B.2.4.
XI.M19	Steam Generator Tube Integrity	Not Applicable. Columbia is a BWR design that does not utilize steam generators.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water Program See Section B.2.42.
XI.M21	Closed-Cycle Cooling Water System	Closed Cooling Water Chemistry Program See Section B.2.13.
XI.M22	Boraflex Monitoring	Not Applicable. Spent fuel racks at Columbia use Boron Carbide plates as the neutron absorber (rather than Boraflex), as described in FSAR Section 9.1.2.2.1.
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Material Handling System Inspection Program See Section B.2.39.
XI.M24	Compressed Air Monitoring	Not credited for aging management. Operating experience shows that the air and gas is dry for most systems except in certain locations for which the plant-specific Air Quality Sampling Program is credited (See Section B.2.2).
XI.M25	BWR Reactor Water Cleanup System	Not credited for aging management. Cracking of the stainless steel RWCU piping components within the augmented ISI boundary is managed by the BWR Stress Corrosion Cracking Program (See Section B.2.8).
XI.M26	Fire Protection	Fire Protection Program See Section B.2.25.
XI.M27	Fire Water System	Fire Water Program See Section B.2.26.
XI.M28	Buried Piping and Tanks Surveillance	Not credited for aging management. The alternate XI.M34 option is credited for aging management. See Section B.2.5 for the alternate Buried Piping and Tanks Inspection Program.
XI.M29	Aboveground Steel Tanks	Aboveground Steel Tanks Inspection See Section B.2.1.
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry Program See Section B.2.29.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance Program See Section B.2.46.
XI.M32	One-Time Inspection	Chemistry Program Effectiveness Inspection See Section B.2.12. Cooling Units Inspection See Section B.2.14. Diesel-Driven Fire Pumps Inspection See Section B.2.18. Diesel Starting Air Inspection See Section B.2.16. Diesel Systems Inspection See Section B.2.17. Flexible Connection Inspection See Section B.2.27. Heat Exchangers Inspection See Section B.2.30. Lubricating Oil Inspection See Section B.2.37. Monitoring and Collection Systems Inspection See Section B.2.41. Service Air System Inspection See Section B.2.48. Supplemental Piping/Tank Inspection See Section B.2.51.
XI.M33	Selective Leaching of Materials	Selective Leaching Inspection See Section B.2.47.
XI.M34	Buried Piping and Tanks Inspection	Buried Piping and Tanks Inspection Program See Section B.2.5.
XI.M35	One-time Inspection of ASME Code Class 1 Small-Bore Piping	Small Bore Class 1 Piping Inspection See Section B.2.49.
XI.M36	External Surfaces Monitoring	External Surfaces Monitoring Program See Section B.2.23.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.M37	Flux Thimble Tube Inspection	Not Applicable. Columbia is a BWR design that does not utilize flux thimbles.
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not credited for aging management. The External Surfaces Monitoring Program (See Section B.2.23) and Preventive Maintenance – RCIC Turbine Casing (See Section B.2.44) are credited instead for aging management of internal surfaces. Confirmation that aging is not occurring on internal surfaces is provided by the Cooling Units Inspection (See Section B.2.14), the Monitoring and Collection Systems Inspection (See Section B.2.41), and the Supplemental Piping/Tank Inspection (See Section B.2.51).
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis Program See Section B.2.36.
XI.S1	ASME Section XI, Subsection IWE	Inservice Inspection (ISI) Program – IWE See Section B.2.34.
XI.S2	ASME Section XI, Subsection IWL	Not Applicable. Columbia has a General Electric Mark II steel containment, as described in FSAR Section 3.8.2.1.
XI.S3	ASME Section XI, Subsection IWF	Inservice Inspection (ISI) Program – IWF See Section B.2.35.
XI.S4	10 CFR Part 50, Appendix J	Appendix J Program See Section B.2.3.
XI.S5	Masonry Wall Program	Masonry Wall Inspection See Section B.2.38.
XI.S6	Structures Monitoring Program	Structures Monitoring Program See Section B.2.50.
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Water Control Structures Inspection See Section B.2.53.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.S8	Protective Coating Monitoring and Maintenance Program	Not credited for aging management. Columbia does not credit coatings inside the containment to manage the effects of aging for structures and components or to ensure that the intended functions of coated structures and components are maintained. Therefore, these coatings do not have an intended function and do not require aging management for license renewal.
XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program See Section B.2.19.
XI.E2	Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program See Section B.2.20.
XI.E3	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program See Section B.2.32.
XI.E4	Metal-Enclosed Bus	Metal-Enclosed Bus Program See Section B.2.40.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
XI.E5	Fuse Holders	Not credited for aging management. There are no in-scope fuse holders that contain fuses which are routinely manipulated. The fuse boxes are not exposed to weather conditions or chemical contamination, and due to the Columbia location in rural central Washington, they are not exposed to industrial pollution or salt deposition. An inspection of a sample of the passive fuse boxes showed that they are clean and dry, with no evidence of corrosion. Similarly, ohmic heating, thermal cycling, electrical transients, and vibration do not apply to the passive fuse boxes at Columbia because the fuses are not heavily loaded and do not experience frequent electrical and thermal cycling. Vibration is an induced aging mechanism, and is not applicable because the electrical boxes are securely mounted on walls.
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection See Section B.2.21.
NUREG-1801 Chapter X		
X.M1	Metal Fatigue of Reactor Coolant Pressure Boundary	Fatigue Monitoring Program See Section B.2.24.
X.S1	Concrete Containment Tendon Prestress	Not Applicable. Columbia has a General Electric Mark II steel containment and this structure does not contain pre-stressed tendons, as described in FSAR Section 3.8.2.1.
X.E1	Environmental Qualification (EQ) of Electrical Components	EQ Program See Section B.2.22.
Columbia Plant-Specific Programs		
N/A	Plant-Specific Program	Air Quality Sampling Program See Section B.2.2.

Table B-1
Correlation of NUREG-1801 and Columbia Aging Management Programs (continued)

Number	NUREG-1801 Program	Corresponding Columbia AMP
N/A	Plant-Specific Program	High-Voltage Porcelain Insulators Aging Management Program See Section B.2.31.
N/A	Plant-Specific Program	Potable Water Monitoring Program See Section B.2.43.
N/A	Plant-Specific Program	Preventive Maintenance – RCIC Turbine Casing See Section B.2.44.

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Aboveground Steel Tanks Inspection Section B.2.1	New	--	Yes	--	--
Air Quality Sampling Program Section B.2.2	Existing	--	--	Yes	--
Appendix J Program Section B.2.3	Existing	Yes	--	--	--
Bolting Integrity Program Section B.2.4	Existing	--	Yes	--	--
Buried Piping and Tanks Inspection Program Section B.2.5	Existing	Yes	--	--	Yes
BWR Feedwater Nozzle Program Section B.2.6	Existing	Yes	--	--	--
BWR Penetrations Program Section B.2.7	Existing	Yes	--	--	--
BWR Stress Corrosion Cracking Program Section B.2.8	Existing	Yes	--	--	--
BWR Vessel ID Attachment Welds Program Section B.2.9	Existing	Yes	--	--	--

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
BWR Vessel Internals Program Section B.2.10	Existing	Yes	--	--	--
BWR Water Chemistry Program Section B.2.11	Existing	Yes	--	--	--
Chemistry Program Effectiveness Inspection Section B.2.12	New	Yes	--	--	--
Closed Cooling Water Chemistry Program Section B.2.13	Existing	--	Yes	--	Yes
Cooling Units Inspection Section B.2.14	New	Yes	--	--	--
CRDRL Nozzle Program Section B.2.15	Existing	Yes	--	--	--
Diesel Starting Air Inspection Section B.2.16	New	Yes	--	--	--
Diesel Systems Inspection Section B.2.17	New	Yes	--	--	--
Diesel-Driven Fire Pumps Inspection Section B.2.18	New	Yes	--	--	--

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program Section B.2.19	New	Yes	--	--	--
Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program Section B.2.20	New	Yes	--	--	--
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection Section B.2.21	New	--	Yes	--	--
EQ Program Section B.2.22	Existing	Yes	--	--	--
External Surfaces Monitoring Program Section B.2.23	Existing	Yes	--	--	Yes
Fatigue Monitoring Program Section B.2.24	Existing	Yes	--	--	Yes
Fire Protection Program Section B.2.25	Existing	--	Yes	--	--

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Fire Water Program Section B.2.26	Existing	Yes	--	--	Yes
Flexible Connection Inspection Section B.2.27	New	--	Yes	--	--
Flow-Accelerated Corrosion (FAC) Program Section B.2.28	Existing	Yes	--	--	Yes
Fuel Oil Chemistry Program Section B.2.29	Existing	--	Yes	--	--
Heat Exchangers Inspection Section B.2.30	New	Yes	--	--	--
High-Voltage Porcelain Insulators Aging Management Program Section B.2.31	Existing	--	--	Yes	--
Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program Section B.2.32	New	Yes	--	--	--
Inservice Inspection (ISI) Program Section B.2.33	Existing	Yes	--	--	--
Inservice Inspection (ISI) Program – IWE Section B.2.34	Existing	Yes	--	--	--

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Inservice Inspection (ISI) Program – IWF Section B.2.35	Existing	Yes	--	--	--
Lubricating Oil Analysis Program Section B.2.36	Existing	Yes	--	--	Yes
Lubricating Oil Inspection Section B.2.37	New	Yes	--	--	--
Masonry Wall Inspection Section B.2.38	Existing	Yes	--	--	Yes
Material Handling System Inspection Program Section B.2.39	Existing	Yes	--	--	Yes
Metal-Enclosed Bus Program Section B.2.40	New	--	Yes	--	--
Monitoring and Collection Systems Inspection Section B.2.41	New	Yes	--	--	--
Open-Cycle Cooling Water Program Section B.2.42	Existing	--	Yes	--	Yes
Potable Water Monitoring Program Section B.2.43	Existing	--	--	Yes	Yes

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Preventive Maintenance – RCIC Turbine Casing Section B.2.44	Existing	--	--	Yes	--
Reactor Head Closure Studs Program Section B.2.45	Existing	Yes	--	--	--
Reactor Vessel Surveillance Program Section B.2.46	Existing	Yes	--	--	--
Selective Leaching Inspection Section B.2.47	New	Yes	--	--	--
Service Air System Inspection Section B.2.48	New	Yes	--	--	--
Small Bore Class 1 Piping Inspection Section B.2.49	New	Yes	--	--	--
Structures Monitoring Program Section B.2.50	Existing	Yes	--	--	Yes
Supplemental Piping/Tank Inspection Section B.2.51	New	Yes	--	--	--

Table B-2
Consistency of Columbia Aging Management Programs with NUREG-1801 (continued)

Program Name	New / Existing	Consistent with NUREG-1801	Consistent with NUREG-1801 with Exceptions	Plant-Specific	Enhancement Required
Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program Section B.2.52	New	Yes	--	--	--
Water Control Structures Inspection Section B.2.53	Existing	Yes	--	--	Yes

B.2.1 Aboveground Steel Tanks Inspection

Program Description

The Aboveground Steel Tanks Inspection is a new one-time inspection that will detect and characterize the conditions on the bottom surfaces of the carbon steel condensate storage tanks. The inspection provides direct evidence through volumetric examination as to whether, and to what extent, a loss of material due to crevice, general, or pitting corrosion has occurred or is likely to occur in inaccessible areas (i.e., tank base and bottom surface) that could result in a loss of intended function.

Implementation of the Aboveground Steel Tanks Inspection, in conjunction with the External Surfaces Monitoring Program, will provide added assurance that the pressure boundary integrity of the condensate storage tanks is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Aboveground Steel Tanks Inspection is a new one-time inspection for Columbia that, in conjunction with the External Surfaces Monitoring Program, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M29, "Aboveground Steel Tanks," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Preventive Actions**

  There is no sealant or caulking at the interface edge between the condensate storage tanks and the concrete foundation.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Aboveground Steel Tanks Inspection includes the base (bottom surface and foundation pad interface) of the condensate storage tanks (COND-TK-1A and COND-TK-1B).

  Volumetric examinations will be conducted on sample locations at the tank base to detect evidence of a loss of material due to crevice, general, or pitting corrosion or to confirm a lack thereof.

Periodic inspection of the external surfaces of the tanks (including protective coatings), other than the tank bottoms, is included in the scope of the External Surfaces Monitoring Program.

- Preventive Actions
  The external surfaces of the condensate storage tanks have protective coatings that are consistent with industry practice. However, there is no sealant or caulking at the interface edge between the tanks and concrete foundation.

  No other actions are taken as part of the Aboveground Steel Tanks Inspection or the External Surfaces Monitoring Program to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The Aboveground Steel Tanks Inspection will determine wall thickness as a measure of loss of material for the tank bottom.

  The related parameters inspected by the External Surfaces Monitoring Program include visual evidence of a loss of material or other degradation.

- Detection of Aging Effects
  The Aboveground Steel Tanks Inspection will use established volumetric examination techniques performed by qualified personnel to inspect locations on the bottom surface of a condensate storage tank to determine whether, and to what extent, a loss of material has occurred or is likely to occur during the period of extended operation.

  The Aboveground Steel Tanks Inspection will be conducted after the issuance of the renewed license and prior to the end of the current operating license for Columbia, with sufficient time to implement programmatic oversight for the period of extended operation. The activities will be conducted no earlier than 10 years prior to the end of the current operating license, so that conditions are more representative of the conditions expected during the period of extended operation.

  The results of this inspection will supplement the existing inspection of accessible external surfaces conducted by the External Surfaces Monitoring Program.

- Monitoring and Trending
  No actions are taken as part of the Aboveground Steel Tanks Inspection to monitor or trend inspection results. This is a one-time inspection activity that will use volumetric examination techniques to determine if, and to what extent, further actions, including monitoring and trending, may be required.

The examination techniques for accessible external surfaces, including the condensate storage tanks, are described in the External Surfaces Monitoring Program.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria, i.e., minimum wall thickness. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

  Acceptance criteria for degradation of external surfaces, including the coatings for the condensate storage tanks, are described in the External Surfaces Monitoring Program.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Aboveground Steel Tanks Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The inspection provides for confirmation of material conditions near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

  No instances of degradation of condensate storage tanks were identified in a review of condition reports. However, to provide added assurance that the component intended function will be maintained during the period of extended operation, inspection of the bottom surface is conservatively warranted.

The operating experience associated with the existing External Surfaces Monitoring Program, which includes the accessible portions of the condensate storage tanks, is addressed under the External Surfaces Monitoring Program evaluation.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Aboveground Steel Tanks Inspection (in conjunction with the External Surfaces Monitoring Program) will verify that there are no aging effects requiring management for the bottom surfaces of the condensate storage tanks or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the condensate storage tank intended function will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.2 Air Quality Sampling Program

Program Description

The Air Quality Sampling Program will mitigate degradation due to loss of material for carbon steel components in the Diesel Starting Air (DSA) System that contain compressed air and are within the scope of license renewal, to ensure that the integrity of piping and components is maintained. The Air Quality Sampling Program also ensures that the Control Air System (CAS) remains dry and free of contaminants, thereby validating the aging management review conclusion that there are no aging effects that require management. The Air Quality Sampling Program is a combination prevention and condition monitoring program. The program is based on existing commitments to NRC Generic Letter 88-14 and comprises periodic air quality sampling and corresponding actions to remove moisture and particulates from the CAS and DSA systems. The program also performs periodic UT inspections of DSA System air receivers to ensure the pressure boundary integrity is maintained.

Prior to the period of extended operation, the Air Quality Sampling Program will be supplemented by a separate one-time inspection of the piping and components downstream of the DSA System dryers (excluding the DSA System air receivers), based on plant-specific operating experience. The Diesel Starting Air Inspection will detect and characterize the extent to which degradation has occurred in the DSA System dryers and the downstream piping and components (excluding the DSA System air receivers) and provide confirmation that the integrity of the piping and components will be maintained for the period of extended operation.

NUREG-1801 Consistency

The Air Quality Sampling Program is an existing Columbia program that is plant-specific. NUREG-1801 includes a Compressed Air Monitoring Program (XI.M24). Both the NUREG-1801 and Columbia programs are based on the results of responses to Generic Letter (GL) 88-14. However, as described in the Energy Northwest responses to GL 88-14 and subsequent NRC acceptance, the Columbia program is comprised of periodic sampling for air quality. Therefore, the other portions of the NUREG-1801, XI.M24 program are not applicable to Columbia.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Air Quality Sampling Program is credited with managing loss of material for subject components in the DSA System. The scope of the Air Quality Sampling Program includes periodic sampling of the DSA System air quality and corresponding actions, if unacceptable moisture or contaminants are detected, to

mitigate loss of material for steel portions of the system. The scope of the program also includes the performance of biennial UT inspections of the DSA System air receivers to ensure that their pressure boundary integrity will be maintained.

In addition, the scope of the Air Quality Sampling Program includes periodic sampling of the air quality in the CAS to ensure that the compressed air environment remains dry and free of contaminants, thereby ensuring that no aging effects require management for the system.

- Preventive Actions
  The Air Quality Sampling Program includes periodic air sampling (for particulates, hydrocarbons, and dewpoint) of the CAS and DSA systems, to ensure acceptable air quality and corresponding actions, such as dewpoint reduction, if the results are outside acceptable limits. In addition, based on site operating experience, the program involves desiccant inspection and replenishment, air receiver dewpoint reduction, and air receiver blowdown activities, which are conducted as necessary to minimize the accumulation of moisture in the DSA System and any resulting corrosion to system components.

- Parameters Monitored or Inspected
  As described for *Preventive Actions* above, the Air Quality Sampling Program periodically samples the CAS and DSA systems for hydrocarbons, dewpoint, and particulates to verify proper air quality and ensure that the intended function of the systems is maintained. The Air Quality Sampling Program also conducts UT inspections of the DSA System air receivers to determine wall thickness. Inspections are performed by qualified personnel using established nondestructive examination (NDE) techniques for the components being inspected (i.e., ultrasonic examination). Visual inspection of tank internals for evidence of corrosion and corrosion products may be performed. In addition, the Air Quality Sampling Program is supplemented by the separate one-time Diesel Starting Air Inspection for the DSA System dryers and downstream piping and components (excluding the DSA System air receivers) to characterize conditions and provide additional confirmation that the intended function will be maintained through the period of extended operation.

- Detection of Aging Effects
  The Air Quality Sampling Program does not directly inspect for or detect the effects of aging in the CAS. Rather, as described for the *Preventive Actions* element above, the presence of an environmental stressor (moisture), which could lead to corrosion of system components, is detected and moisture, if any, is removed to ensure air quality is maintained.

  To detect loss of material prior to a loss of component intended function, the Air Quality Sampling Program performs UT inspections to measure the wall thickness of the DSA System air receivers.

Refer to the *Operating Experience* discussion below for information on the effectiveness of the Air Quality Sampling Program in minimizing the conditions that could result in the effects of aging (corrosion) in the DSA System. See also the one-time Diesel Starting Air Inspection, which is evaluated separately.

- Monitoring and Trending
  Air quality sampling of the CAS and DSA systems is performed periodically, depending on the results of previous testing. The UT inspection of the DSA System air receivers is performed on a biennial basis. Results are kept in permanent plant files and are available for trending analysis as necessary. Recurring instances of DSA System air quality outside acceptable limits and decreases in wall thickness of the DSA System air receivers have been trended and evaluated through the corrective action program.

- Acceptance Criteria
  Acceptance criteria for the CAS and DSA compressed air are specified for particulates, hydrocarbons, and dewpoint in the surveillance procedures. If the CAS acceptance criteria are not met, the procedure directs entering the failure into the corrective action program which drives actions to reduce the dew point. If the DSA System acceptance criteria are not met, then the procedure directs entering the failure into the corrective action program and directs procedural actions to reduce the dew point.

  Indications or relevant conditions of degradation detected during the inspections of the DSA System air receivers will be compared to pre-determined acceptance criteria (i.e., minimum wall thickness). If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  As described in the Energy Northwest responses to GL 88-14, and confirmed by subsequent site operating experience, air quality testing continues to show that the compressed air is essentially dry and contaminant free. With the exception of the DSA System, there have been no failures or significant degradation of components in compressed air systems, such as the CAS and the Service Air System.

  Industry operating experience is also included. Experience from Beaver Valley was reviewed and confirmed that erosion and corrosion issues should not be expected in the CAS and SA systems at Columbia. Work requests were initiated to perform inspections, which further confirmed that loss of material is not a concern in the CAS and SA systems.

  Recurring dewpoint problems have been experienced with the DSA System, which is more noticeable during the summer months, when ambient humidity is higher. Dewpoint, or moisture content, in the DSA System is a concern for the long-term effects of corrosion and corrosion products on DSA System components. The most critical point in the DSA System for moisture control is at the air receivers and the high-pressure portion of the system upstream of the pressure control valves. Degradation has been identified in the DSA System (e.g., due to excessive moisture content), where the dewpoint has been shown to average +5°C. This degradation has been evaluated by the corrective action process.

  The quarterly sampling of CAS has been effective at maintaining dry, contaminant-free air, thereby minimizing the conditions for degradation. For the DSA System, additional actions to reduce dewpoint, replenish desiccant, and blow down the air receivers are necessary to ensure dry air and to effectively maintain the DSA System air quality.

Required Enhancements

None.

Conclusion

The Air Quality Sampling Program will manage loss of material for susceptible DSA System components exposed to compressed air through its monitoring activities. The Air Quality Sampling Program also will ensure that the CAS environment remains dry and free of contaminants, thereby ensuring that no aging effects require management for the system. The Air Quality Sampling Program, supplemented by the one-time Diesel Starting Air Inspection prior to entering the period of extended operation, provides reasonable assurance that the aging effects will be managed such that DSA components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.3 Appendix J Program

Program Description

The Appendix J Program is a monitoring program that detects degradation of the Primary Containment and systems penetrating the Primary Containment. The Appendix J Program provides assurance that leakage from the Primary Containment will not exceed maximum values for containment leakage. The regulatory basis for the Appendix J Program includes 10 CFR 50 Appendix J Option B, Regulatory Guide 1.163 (Performance-Based Containment Leak-Test Program), and NEI 94-10 (Industry Guideline for Implementing Performance Based Option of 10 CFR Part 50, Appendix J).

The Appendix J Program provides reasonable assurance that the effects of aging are adequately managed to ensure that leakage through the Primary Containment and systems and components penetrating the Primary Containment does not exceed allowable values specified in technical specifications and that their intended function is performed consistent with the current licensing basis for the period of extended operation.

NUREG-1801 Consistency

The Appendix J Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S4, "10 CFR Part 50, Appendix J."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

For Columbia, the integrated leakage rates for Type A tests, and the sum of Type B and Type C leakage rate tests, have been less than the maximum allowable leakage rates specified in the Technical Specifications.

Inservice inspections conducted during Refueling Outage 18 (R18) did not identify any significant age-related degradation of the containment and its penetrations. Two deficiencies were found during the ISI-IWE inspection and were reported in the R18 ISI summary report. Both found items dealt with replacement of individual bolts and were not related to containment integrity.

Type B and C leakage rate test results from the 2007 Refueling Outage (R18) are summarized in the local leak rate test post outage report. The R18 local leak rate test involved ninety-one Type B and C air tests. Twenty-five Type B tests were conducted, including the personnel airlock barrel test. All Type B as found leak rates were below their administrative limits with the exception of the containment-side flange (CEP-V-2A), which had a leak rate exceeding its administrative limit. This flange was checked using a soap solution with test pressure applied and showed no external leakage. This visual inspection confirmed that the leakage recorded was into the system rather than a breach of the containment penetration. Sixty-six Type C tests were conducted. All but eight valves had as found leak rates below their administrative limits. The valves with leak rates in excess of their administrative limit required corrective actions to reduce their leak rates. Of the eight valves with as found leak rates in excess of their administrative limits, five required disassembly and rework, and one valve was replaced. The remaining two valves were successfully flushed and as-left tested without disassembly.

The total as found leakage at the beginning of Refueling Outage 19 (R19) was 19,712 standard cubic centimeters per minute (sccm). This equates to 16.2 percent of the total allowable containment leakage (La) of 121,536 sccm. The values from previous refueling outages (R18) and (R17) were 13,683 sccm and 20,879 sccm respectively.

The total as left leakage at the end of R19 was 13,098 sccm. This equates to 10.8 percent of the total allowable containment leakage (La) of 121,536 sccm and well below the maximum allowable startup containment leakage rate of 0.6La. The values from the previous refueling outages (R18) and (R17) were 14,051 sccm and 17,423 sccm, respectively.

The results of previous Type A tests are shown below. No Type A tests have failed to meet their acceptance criteria at Columbia.

Test Date	Total Leakage (percent)	Acceptance Limit (percent)
02/16/1984	0.2758	0.50
06/17/1987	0.3241	0.50
06/09/1991	0.319	0.50
07/20/1994	0.330	0.50
06/14/2009	0.3418	0.50

The health of the Appendix J Program is reported periodically in terms of performance indicators. The program health reports for 2007 and 2008 indicated no age-related concerns for systems and components within the scope of the Appendix J Program.

The Appendix J Program has been effective in managing the identified aging effects. The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Appendix J Program will be capable of detecting and managing aging effects for the Primary Containment and systems and components penetrating the Primary Containment. The continued implementation of the Appendix J Program provides reasonable assurance that the aging effects will be managed such that the Primary Containment will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

B.2.4 Bolting Integrity Program

Program Description

The Bolting Integrity Program is a condition monitoring program that consists of existing Columbia activities that, in conjunction with other credited programs (identified in discussions below), address the management of aging for the bolting of subject mechanical components and structural connections within the scope of license renewal. The Bolting Integrity Program relies on manufacturer and vendor information and industry recommendations (in EPRI NP-5067, "Good Bolting Practices") for the proper selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections. The Bolting Integrity Program consists of the periodic inspection of bolting for indications of degradation such as leakage, loss of material due to corrosion, loss of pre-load, and cracking due to SCC and fatigue.

NUREG-1801 Consistency

The Bolting Integrity Program is a combination of existing activities that are consistent with the 10 elements of an effective aging management program as described in NUREG-1801 Section XI.M18, "Bolting Integrity," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Preventive Actions (and Scope of Program)**

  The Bolting Integrity Program does not explicitly address the guidelines outlined in EPRI NP-5769, or as delineated in NUREG-1339. However, the Bolting Integrity Program does rely on the recommendations of the manufacturer and vendor and the industry, contained in related EPRI document NP-5067, including proper material selection, preload, and assembly.

- **Monitoring and Trending**

  Periodic inspection of bolting, other than of the Class 1, 2, 3, and MC bolting performed by the Inservice Inspection (ISI) Program and Inservice Inspection (ISI) Program – IWF, is performed through the External Surfaces Monitoring Program or Structures Monitoring Program, including follow-up inspections if leakage or degradation is detected. The frequency of follow-up inspections is established by engineering evaluation of the identified problem.

- **Acceptance Criteria**

  The Bolting Integrity Program does not specify acceptance criteria for bolting. However, the Inservice Inspection (ISI) Program, Inservice Inspection (ISI) Program – IWF, Structures Monitoring Program, and External Surfaces Monitoring Program, through which the periodic visual inspections of mechanical and structural components within the scope of license renewal are performed, do, or will prior to the period of extended operation, include acceptance criteria for evidence of degradation of components, including the bolting.

Required Enhancements

None.

Operating Experience

Review of operating experience shows that the Bolting Integrity Program, following the guidance of EPRI NP-5067, has been effective in managing aging effects.

No instances of cracking have been identified for bolting or fasteners, although some corroded bolting and facing surfaces (e.g., from general corrosion or as a result of leakage) have been identified at Columbia and corrected. For example, corrosion has been identified for some pump column-to-bowl bolting, and on some valve body-to-bonnet bolting. Corroded bolting has been replaced, and leaking bolted joints and closures have been repaired. There have also been instances of system leaks that may have been due to loss of preload that have been identified and corrected by existing activities in the Bolting Integrity Program.

Conclusion

The Bolting Integrity Program will manage loss of material, loss of pre-load, and cracking for the bolting of pressure-retaining mechanical components and structural connections. The Bolting Integrity Program provides reasonable assurance that the aging effects will be managed such that bolting will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

B.2.5 Buried Piping and Tanks Inspection Program

Program Description

The Buried Piping and Tanks Inspection Program will manage the effects of loss of material due to corrosion on the external surfaces of piping and tanks exposed to a buried environment.

The Buried Piping and Tanks Inspection Program is a combination of a mitigation program (consisting of protective coatings) and a condition monitoring program (consisting of visual inspections). Integrity of coatings will be inspected when components are excavated for maintenance or other reasons. If an opportunistic inspection has not occurred between year 30 and year 38, an excavation of a section of buried piping for the purpose of inspection will be performed before year 40. An additional inspection of buried piping will be performed within 10 years after entering the period of extended operation.

The Buried Piping and Tanks Inspection Program will continue to ensure that the pressure boundary integrity of the subject components is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M34, "Buried Piping and Tanks Inspection."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope of Program –**

  Revise the site program document to include the buried portions of the Radwaste Building Outside Air (WOA) piping.

- **Detection of Aging Effects –**

  Require that an inspection of a representative sample of buried piping be performed within the 10-year period prior to entering the period of extended operation (i.e., between year 30 and year 40).

  Require an additional inspection of a representative sample of buried piping be performed within 10 years after entering the period of extended operation (i.e., between year 40 and year 50).

Operating Experience

No history of piping degradation due to external corrosion of buried piping was identified for Columbia through searches of operating experience or discussions with program owners. Columbia operating experience demonstrates that the coating of buried steel piping and tanks is effective in managing the effects of aging. Plant design considerations addressed the potential for degradation of buried piping components through the application of protective coatings.

A review was conducted of station piping failures, and it was determined that there had been no documented failures attributed to externally-initiated corrosion. Identified instances of leakage associated with buried piping have been the result of internal corrosion.

The environmental conditions at Columbia are very good based on the sandy soil and electrolyte resistivity of the soil which is considered very high. This has resulted in minimal degradation of buried piping as evidenced by excavations of certain sections of piping for examination. There have been no significant areas of degradation caused by protective coating failure. This was determined after a section of buried Standby Service Water (SW) System piping was excavated and evaluated in 2007.

Conclusion

The Buried Piping and Tanks Inspection Program will manage loss of material due to corrosion for susceptible piping components and tanks in buried environments. The Buried Piping and Tanks Inspection Program, with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.6 BWR Feedwater Nozzle Program

Program Description

The BWR Feedwater Nozzle Program manages cracking due to SCC/IGA and flaw growth of the feedwater nozzles. The BWR Feedwater Nozzle Program is an existing program in accordance with ASME Section XI and NRC augmented requirements.

The program consists of (a) enhanced inservice inspection in accordance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 edition including the 2002 and 2003 Addenda) and the recommendations of General Electric (GE) NE-523-A71 0594-A, and (b) system modifications to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of the feedwater nozzles.

As described in FSAR Section 5.3.3.1.4.5, the solution of the feedwater nozzle cracking problems involved several elements, including material selection and processing, nozzle clad elimination, and thermal sleeve and sparger redesign. The Columbia sparger design includes a welded thermal sleeve such that there is no thermal sleeve bypass and no rapid thermal cycling of the blend radius for each feedwater nozzle. Stainless steel cladding of the Columbia feedwater nozzles was not included in the original design.

The original feedwater (FW) flow controller satisfied most of the recommended characteristics of a low flow controller. Consequently, replacement of this controller was not required at Columbia. Columbia rerouted the reactor water cleanup (RWCU) such that it discharges into all six feedwater nozzles.

Columbia performed a pre-service inspection ultrasonic examination of the feedwater nozzle inner radii, bore, and safe end regions. In addition, a pre-service liquid penetrant examination was performed on the accessible areas of all feedwater nozzle inner radius surfaces.

The BWR Feedwater Nozzle Program at Columbia monitors cracking by detection and sizing of cracks using ISI in accordance with ASME Section XI, Subsection IWB. The BWR Feedwater Nozzle Program at Columbia includes augmented inservice inspection (ISI) examinations to monitor crack initiation and growth of the feedwater nozzles. The schedule, examination techniques and personnel qualification recommendations of GE NE-523-A71-0594-A have also been incorporated into the Inservice Inspection (ISI) Program.

All ISI indications are evaluated to the ASME Code requirements for the component involved. Evaluation is performed in accordance with established site procedures that require use of the ASME Code, or other documents such as BWRVIP documents, if applicable.

The BWR Feedwater Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The BWR Feedwater Nozzle Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801 Section XI.M5, "BWR Feedwater Nozzle."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

Review of recent BWR License Renewal Applications identified the following industry experience.

Reactor pressure vessel inner radius section ultrasonic examinations were performed for nozzles N4A, N4B, N4C and N4D at Cooper in 2005. No indications that required evaluation were recorded during these examinations. In 2007, Duane Arnold Energy Center identified the failure of a sparger bracket keeper which allowed interface wear between the mating surfaces of the sparger bracket and the vessel bracket. Temporary repairs were done to make the sparger acceptable for continued use.

Columbia operating experience:

Columbia operating experience, consistent with industry operating experience, shows that the BWR Feedwater Nozzle Program is effective in managing aging effects in that no feedwater nozzle cracking has been observed at Columbia. Inspections of four feedwater nozzles in the spring of 2005 found no unacceptable indications. Inspection of the nozzle, inner radius, bore, and associated safe end of two feedwater nozzles in the spring of 2009 found no unacceptable indications. Therefore, continued implementation of the program provides reasonable assurance that the effects of aging will be managed so that the feedwater nozzles will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The BWR Feedwater Nozzle Program manages cracking of the feedwater nozzles. The BWR Feedwater Nozzle Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.7 BWR Penetrations Program

Program Description

The BWR Penetrations Program manages cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) of stainless steel or nickel alloy reactor vessel penetrations, including reactor vessel instrument penetrations, jet pump instrument penetrations, control rod drive penetrations, and incore instrument penetrations. Columbia inspects all reactor vessel penetrations in accordance with the requirements of ASME Section XI. The ASME Section XI examinations are supplemented by approved BWRVIP reports.

Columbia detects and sizes cracks in accordance with the guidelines of approved BWRVIP documents and the requirements of the ASME Code, Section XI, 2001 Edition, 2003 Addenda, Section XI, IWB-3000, "Standards for Examination Evaluations." Evaluation of flaws in accordance with established site procedures and ASME Code or BWRVIP requirements may result in re-inspection or sample expansion. Acceptance of components for continued service is in accordance with the ASME code or the BWRVIP program guidance, as applicable. Repair and replacement would include the guidance in BWRVIP-53 and BWRVIP-57.

The Columbia instrumentation penetrations are low alloy steel, welded to the reactor vessel with nickel alloy weld material. This configuration is addressed in BWRVIP-49-A and no further inspections beyond ASME Section XI requirements are recommended. The BWR Penetrations Program incorporates BWRVIP-49-A and will be revised if future revisions to BWRVIP-49-A require further inspections.

Columbia's SLC system injects through the core spray nozzles rather than the SLC nozzle. Thus, consistent with Section 1.1 of BWRVIP-27-A, this BWRVIP document does not apply to Columbia. Consequently, cracking of Columbia's SLC penetration is managed by the Inservice Inspection (ISI) Program rather than the BWR Penetrations Program. The BWR Penetrations Program incorporates BWRVIP-27-A and will be revised if future revisions to BWRVIP-27-A make it applicable to Columbia.

The Columbia drain nozzle is low alloy steel and is not susceptible to SCC/IGSCC. Degradation of this penetration is managed by the Inservice Inspection (ISI) Program rather than BWR Penetrations Program.

The BWR Penetrations Program credits portions of the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The BWR Penetrations Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M8, "BWR Penetrations."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

As a participant in the BWRVIP, Columbia is committed to incorporate lessons learned from operating experience of the entire BWR fleet.

Review of recent BWR license renewal applications found the following industry experience.

At Cooper, the nozzle-to-safe-end welds of instrument nozzle and SLC nozzle were ultrasonically examined and found acceptable in 2005. Each of the instrument penetration nozzles were inspected and found acceptable during pressure testing in 2003 and in 2005.

During Refueling Outage (RFO) 16 at Duane Arnold Energy Center inspections of weld susceptible to intergranular stress corrosion cracking (IGSCC) identified flaw indications on three recirculation riser nozzle-to-safe-end welds (RRB-F002 , RRD-F002 and RRF-F002). The original scope of the examinations included three recirculation riser and one core spray nozzle-to-safe-end welds. The inspection scope was therefore expanded to include all of the remaining F002 welds, as well as the other similarly designed core spray welds. One weld was ground flush and re-inspected, and has been dispositioned. Two welds were repaired using weld overlays.

Columbia operating experience:

> Columbia operating experience to date has found no indications of cracking in the reactor vessel penetrations.

Both Columbia and industry operating experience shows that the BWR Penetrations Program has been effective in managing aging effects. Therefore, continued implementation of the program provides reasonable assurance that effects of aging will be managed so that the reactor vessel penetrations crediting this program will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

Conclusion

The BWR Penetrations Program manages cracking of the in-scope reactor vessel penetrations. The BWR Penetrations Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review and crediting this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.8 BWR Stress Corrosion Cracking Program

Program Description

The BWR Stress Corrosion Cracking Program manages stress corrosion cracking for stainless steel and nickel alloy piping, nozzle safe ends, nozzle thermal sleeves, valves, flow elements, and pump casings. The program to manage stress corrosion cracking and intergranular attack (SCC/IGA) in reactor coolant pressure boundary piping made of stainless steel and components made of stainless steel or nickel alloy is delineated in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1. The material includes base metal and welds. The BWR Stress Corrosion Cracking Program meets the requirements of GL 88-01 and BWRVIP-75.

The program consists of (a) preventive measures to mitigate SCC/IGA, and (b) inspection and flaw evaluation to monitor SCC/IGA and its effects. The staff-approved BWRVIP-75 report modified the inspection scope in the GL 88-01 program.

(a) preventive measures to mitigate SCC/IGA

Columbia mitigates stress corrosion cracking by using, and continuing to use, materials resistant to SCC for component replacements and repairs following the recommendations delineated in GL 88-01. Prior to initial plant startup and during the first refueling outage, an induction heating stress improvement (IHSI) process was used on 148 SCC/IGA susceptible piping welds. In the 1994 refueling outage, Columbia performed a mechanical stress improvement process (MSIP) for multiple RPV nozzle to safe end and safe end to pipe welds.

Columbia mitigates aging by maintaining water chemistry in accordance with the current BWRVIP guidelines, as detailed in the BWR Water Chemistry Program. Columbia has implemented hydrogen water chemistry (HWC) and noble metal chemical application (NMCA) to mitigate IGSCC.

(b) Inspection and flaw evaluation

The Columbia program detects and sizes cracks in accordance with the requirements of the ASME Code, Section XI, supplemented by guidelines of approved BWRVIP documents. Inspection of piping to detect and size cracks is performed in accordance with the staff positions on schedule, methods, and personnel and sample expansion included in GL 88-01 and BWRVIP-75. If indications are found, sample expansion occurs per BWRVIP-75.

In response to GL 88-01, Columbia committed to using ASME Section XI Section IWB-3600 of the ASME Code for methods and criteria for crack evaluation and repair. Columbia committed to notify the Commission if a flaw is found that does not meet Section XI, IWB-3500 criteria for continued operation without evaluation.

Further, Columbia committed to submit an evaluation of the flaw justifying continued operation or the repair plans to the Commission for approval prior to resuming operation. Resumption of operation will not be allowed until Commission approval has been granted.

Columbia monitors reactor coolant leakage as recommended by GL 88-01 in compliance with Technical Specification 3.4.5.

The BWR Stress Corrosion Cracking Program credits portions of the BWR Water Chemistry Program.

NUREG-1801 Consistency

The BWR Stress Corrosion Cracking Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M7, "BWR Stress Corrosion Cracking."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

Review of recent BWR license renewal applications found the following industry experience.

In 2000, Cooper Nuclear Station safe end nozzles and piping components were ultrasonically examined and found acceptable. Examinations in 2000 and in 2005 for a nozzle cap had recordable indications, which were caused by ID geometry and determined to be acceptable.

During Refueling Outage (RFO) 16 at Duane Arnold Energy Center, inspections of welds susceptible to intergranular stress corrosion cracking (IGSCC) identified flaw indications on three recirculation riser nozzle-to-safe-end welds (RRB-F002 , RRD-F002 and RRF-F002). The original scope of the examinations included three recirculation riser welds and one core spray nozzle-to-safe-end weld. The inspection scope was therefore expanded to include all of the remaining F002 welds, as well as the other similarly designed core spray welds. One weld was ground flush and re-inspected, and has been dispositioned. Two welds were repaired using weld overlays.

Columbia operating experience:

One indication was identified in stainless steel recirculation system piping to valve weld 20RRC(6)-8 during Refuel Outage 6 (1991). The sample size was expanded in accordance with GL 88-01. The indication did not show IGSCC characteristics; however, it was evaluated as IGSCC. The indication was determined to be acceptable for continued operation without repair. In 1996, after four successive inspections without significant change in the indication, the indication was reclassified to an IGSCC Category E weld in accordance with GL 88-01. The NRC staff was kept informed of the indication status and concurred with the actions taken and the reclassification of the indication. The weld was examined in 2001 using technology approved as part of the EPRI Performance Demonstration Initiative and no indications associated with IGSCC were identified. It was determined that the indication was not due to IGSCC and the weld was reclassified as Category B. All previous examinations were re-evaluated using the 2001 methods, and it was concluded that the indication had shown no identifiable growth in either length or depth in the 10 years that it had been monitored.

A second indication, identified in RRC nozzle to safe end weld 24RRC(2)A-1 in 1998, has been verified to be an original construction weld repair. There is no indication of IGSCC in this weld.

Therefore, continued implementation of the program provides reasonable assurance that stress corrosion cracking of austenitic stainless steel will be managed so that components crediting the BWR Stress Corrosion Cracking Program will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The BWR Stress Corrosion Cracking Program manages cracking of stainless steel and nickel alloy components. The BWR Stress Corrosion Cracking Program provides reasonable assurance that cracking of stainless steel and nickel alloy components will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.9 BWR Vessel ID Attachment Welds Program

Program Description

The BWR Vessel ID Attachment Welds Program will manage cracking due to SCC/IGA of the welds for internal attachments to the reactor vessel.

The BWR Vessel ID Attachment Welds Program performs examinations and inspections as required by ASME Section XI, augmented by BWRVIP-48-A. These inspections include enhanced visual inspections with resolution to the guidelines in BWRVIP-03.

Inspections are scheduled in accordance with the ASME Code, Section XI. Approval for any exceptions to the ASME Code requirements is requested from the NRC via a Relief Request or an Exemption Request. Columbia has scheduled inspections in accordance with ASME Section XI, IWB-2400 and approved BWRVIP-48-A guidelines. If flaws are detected, the scope of the examination is expanded in accordance with ASME Section XI and BWRVIP-48-A.

Cracks are detected and sized by inspection in accordance with the guidelines of approved BWRVIP documents and the requirements of the ASME Code, Section XI. Evaluation is performed in accordance with established site procedures that require use of the ASME Code and other applicable documents, such as BWRVIP reports.

The program includes preventive measures to mitigate cracking by maintaining water chemistry in accordance with the current BWRVIP guidelines using the BWR Water Chemistry Program.

The BWR Vessel ID Attachment Welds Program credits portions of the BWR Water Chemistry Program, the BWR Vessel Internals Program and the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The BWR Vessel ID Attachment Welds Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801 Section XI.M4, "BWR Vessel ID Attachment Welds."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry operating experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

Review of recent License Renewal Applications found no instances of aging. At Cooper Nuclear Station, a combination of components including guide rod brackets, feedwater sparger brackets, and core spray sparger brackets was examined in 2001 and 2003 with no recordable indications for the guide rod and feedwater sparger brackets. Indications found in 2000 on the core spray sparger brackets were determined to be acceptable. Jet pump riser brace attachment pad welds and steam dryer support brackets were examined in 2003 with no indications. Holddown brackets for the surveillance specimens and steam dryer were examined in 2005 with no indications. The jet pump riser brace attachment was also examined with no indications. A review of site-specific operating experience at Duane Arnold Energy Center found no instances of degradation to the vessel ID attachment welds which required repairs.

Columbia operating experience:

Columbia operating experience to date has not detected any flaws in reactor vessel attachment welds. Inspections of the core spray sparger and supply piping attachment welds and five jet pump riser brace attachment welds during Refuel Outage 16 (2003) found no recordable indications. Inspection of the remaining attachment welds during Refuel Outage 17 (2005), including the feedwater bracket, steam dryer, and specimen holders, found no recordable indications.

Columbia site-specific operating experience agrees with industry operating experience in that the BWR Vessel ID Attachment Welds Program has been effective in managing aging effects. Therefore, continued implementation of the program provides reasonable assurance that the effects of aging will be managed so that the reactor vessel inside diameter (ID) attachment welds will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The BWR Vessel ID Attachment Welds Program manages cracking of the vessel internal attachment welds. The BWR Vessel ID Attachment Welds Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.10 BWR Vessel Internals Program

Program Description

The BWR Vessel Internals Program will manage cracking due to SCC/IASCC, SCC/IGA, flaw growth, and flow-induced vibration for various components and subcomponents of the reactor vessel internals. The Columbia program includes mitigation, inspection, and repair. The BWR Vessel Internals Program incorporates all of the BWRVIP guidance documents, including those specifically called out in NUREG-1801, Section XI.M9.

(a) mitigation

Columbia mitigates reactor vessel internals cracking by maintaining water chemistry in accordance with the current BWRVIP guidelines using the BWR Water Chemistry Program.

(b) inspection

Inspection is performed by the Inservice Inspection (ISI) Program as required by the ASME Code. Augmented inspections as recommended by the BWRVIP program are performed by the BWR Vessel Internals Program. The BWRVIP requirements typically include more stringent inspections and components beyond the ASME requirements. The Columbia program includes enhanced visual examinations, including the equipment and environmental conditions necessary to achieve the resolution recommended by the BWRVIP guidelines.

Columbia implements all the BWRVIP requirements, including re-inspection and sample expansion requirements. Columbia detects and sizes cracks in accordance with the guidelines of approved BWRVIP documents and the requirements of the ASME Code, Section XI, 2001 Edition, 2003 Addenda.

Columbia evaluates all flaws in accordance with either the ASME code or BWRVIP guidance. Flaw evaluations that deviate from the guidance in BWRVIP reports are submitted to the NRC for approval.

(c) repair

Repair or replacement, as necessary, is performed in accordance with approved BWRVIP documents and ASME Section XI, as applicable.

Columbia's top guide will have received neutron fluence exceeding the IASCC threshold (5E20, E>1 MeV) before entering the period of extended operation. Columbia complies with BWRVIP-183. Although BWRVIP-183 has not yet been approved by the NRC staff, it includes the top guide inspections recommended by NUREG-1801. BWRVIP-

183 requires either EVT-1 or UT inspection of 10% of the top guide grid beam cells containing control rod drives and blades every 12 years with at least 5% to be performed within 6 years.

The BWR Vessel Internals Program credits portions of the BWR Water Chemistry Program and the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The BWR Vessel Internals Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801 Section XI.M9, "BWR Vessel Internals."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry operating experience:

> NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.
>
> Review of recent License Renewal Applications shows that BWRs continue to inspect per the BWRVIP guidelines and that occasional indications are found and dispositioned. No indications were reported that required repair or replacement of any component.

Columbia operating experience:

> Columbia operating experience is consistent with industry experience; a large number of examinations are being performed, and an occasional indication is being found and resolved. Columbia has found cracking of the core shroud, cracking of the steam dryer, gaps on the jet pump set screws, and wear of the jet pump wedges. All conditions have been evaluated and actions taken in accordance with approved BWRVIP documents for the component involved. No aging mechanisms not already

addressed by the BWRVIP have been discovered. The extensive industry operating experience with the BWRVIP to date provides assurance that the program is effective in managing the effects of aging so that components crediting these programs will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

INPO conducted a BWRVIP vessel and internals review visit at Columbia during 2005 that resulted in three recommendations for Columbia. Columbia conducted a self assessment in 2006 and determined that the BWRVIP program was effective and that the INPO recommendations had been properly implemented. The self assessment also noted that there was strong commitment to the BWRVIP program among Columbia organizations.

The BWR Vessel Internals Program includes provisions to adopt future changes to BWRVIP guidelines. This ensures that operating experience from the BWR fleet will continue to be incorporated into the Columbia program.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The BWR Vessel Internals Program manages cracking for the reactor vessel internals components and subcomponents. The BWR Vessel Internals Program provides reasonable assurance that the effects of aging will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.11 BWR Water Chemistry Program

Program Description

The BWR Water Chemistry Program will mitigate damage related to loss of material due to corrosion or erosion, cracking due to SCC, and reduction of heat transfer due to fouling of plant components that are within the scope of license renewal and contain or are exposed to treated water, treated water in the steam phase, reactor coolant, or treated water in a sodium pentaborate solution. The program manages the relevant conditions (e.g., concentrations of chlorides, oxygen, and sulfates) that could lead to the onset and propagation of a loss of material, cracking, or reduction of heat transfer through proper monitoring and control consistent with the current EPRI water chemistry guidelines. The relevant conditions are specific parameters such as sulfates, halogens, dissolved oxygen, and conductivity that could lead to, or are indicative of, conditions for corrosion or SCC of susceptible materials, as well as erosion and fouling. The BWR Water Chemistry Program is a mitigation program.

The BWR Water Chemistry Program is supplemented by separate one-time inspections of representative areas of treated water systems. One inspection is the Chemistry Program Effectiveness Inspection. This one-time inspection provides further confirmation that loss of material and cracking are effectively mitigated, or to detect and characterize whether, and to what extent, degradation is occurring. The other inspection is the Heat Exchangers Inspection. This one-time inspection provides further confirmation that reduction in heat transfer is effectively mitigated, or to detect and characterize whether, and to what extent, degradation is occurring.

Additionally, the BWR Water Chemistry Program is supplemented by the BWR Feedwater Nozzle Program, BWR Stress Corrosion Cracking Program, BWR Penetrations Program, BWR Vessel ID Attachment Welds Program, BWR Vessel Internals Program, Inservice Inspection (ISI) Program, and Small Bore Class 1 Piping Inspection to provide verification of the program's effectiveness in managing the effects of aging for reactor pressure vessel, reactor vessel internals, and reactor coolant pressure boundary components.

NUREG-1801 Consistency

The BWR Water Chemistry Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M2, "Water Chemistry."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

The BWR Water Chemistry Program is an ongoing program that effectively incorporates the best practices of industry guidance, vendor recommendations, and industry experience in defining chemistry control requirements, monitoring of plant performance in implementing them, and continual review of their adequacy. The program incorporates EPRI guideline documents as well as "lessons learned" from site and other utility operating experience. The program has been, and continues to be, subject to periodic internal and external assessment of the performance to identify strengths, potential adverse trends, and areas for improvement. In addition, quarterly program health reports are generated addressing chemistry performance indicators.

Review of site-specific operating experience did not reveal a loss of component intended function for components exposed to reactor water, feedwater condensate, control rod drive water, accident mitigation water (suppression or fuel pool), or steam that could be attributed to an inadequacy of the BWR Water Chemistry Program. The known chemistry-related problems suffered by other utilities are a consideration in the ongoing refinement of the BWR Water Chemistry Program for Columbia. No change of the BWR Water Chemistry Program was required as a result of these evaluations. Abnormal chemistry conditions are promptly identified, evaluated (with increased sampling to better trend the data), and corrected. Furthermore, the program is periodically updated to the latest guidance documents.

An internal self-assessment of the performance of the BWR Water Chemistry Program is conducted and reported periodically (at least annually) to identify strengths, potentially adverse trends, and areas for improvement. This assessment covers the entire program.

The latest self-assessments noted that the corrective action process is used extensively in the Chemistry Department, and that data review and reporting requirements are in compliance with procedures.

There were also challenges with condenser in-leakage for much of cycle 18; a long-term project to replace the condenser is underway (to solve the leakage problem and issues with copper). Past operating experience has demonstrated the effectiveness of the program in identifying out of specification reactor water chemistry conditions resulting from condenser in-leakage with prompt actions taken to restore below Action Level 1 limits.

Conclusion

The BWR Water Chemistry Program will manage loss of material, cracking, and reduction in heat transfer for susceptible components through monitoring and control of the relevant parameters in treated water (and steam). The BWR Water Chemistry Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.12 Chemistry Program Effectiveness Inspection

Program Description

The Chemistry Program Effectiveness Inspection is a new one-time inspection that will detect and characterize the material conditions in representative low-flow and stagnant areas of plant systems influenced by the BWR Water Chemistry Program, the Fuel Oil Chemistry Program, and the Closed Cooling Water Chemistry Program (which are mitigation programs). The inspection provides direct evidence as to whether, and to what extent, a loss of material due to crevice, general, galvanic, or pitting corrosion (in treated water or fuel oil environments) has occurred. The inspection provides direct evidence as to whether, and to what extent, microbiologically-influenced corrosion (MIC) in a fuel oil environment has occurred. The inspection also provides direct evidence as to whether, and to what extent, cracking due to SCC of susceptible materials in susceptible locations has occurred.

Implementation of the Chemistry Program Effectiveness Inspection will provide confirmation of program effectiveness and further assurance that the integrity of susceptible components is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Chemistry Program Effectiveness Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Chemistry Program Effectiveness Inspection includes the surfaces of copper alloy, copper alloy > 15% zinc (Zn), steel, gray cast iron, nickel alloy, and stainless steel (including cast austenitic stainless steel) components in treated water environments. The scope includes gray cast iron, copper alloy, copper alloy > 15% Zn, steel, and stainless steel components in fuel oil environments.

- Preventive Actions
  No actions are taken as part of the Chemistry Program Effectiveness Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Chemistry Program Effectiveness Inspection include wall thickness and visual evidence of surface degradation as measures of loss of material, or of cracking for stainless steel exposed to treated water above 140 °F and copper alloy > 15% Zn exposed to fuel oil. Inspections will be performed by qualified personnel using established NDE techniques, including visual, volumetric, and surface techniques.

- Detection of Aging Effects
  The Chemistry Program Effectiveness Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on a sample population of subject mechanical components to identify evidence of a loss of material, or cracking of stainless steel exposed to treated water above 140 °F and copper alloy > 15% Zn exposed to fuel oil, or to confirm a lack thereof on the susceptible internal and external surfaces of components.

  A sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Chemistry Program Effectiveness Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and to determine if, and to what extent, further actions may be required. The activity includes increasing the inspection sample size and location if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, susceptible locations, lowest design margin). Unacceptable inspection results (if degradation is detected), if any, will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for further monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria, such as design minimum wall thickness for piping. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Chemistry Program Effectiveness Inspection is a new one-time inspection activity. The inspection provides for confirmation of material conditions, and thereby chemistry program effectiveness, near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience identified instances of microbiologically-influenced corrosion in the fuel oil system associated with the fire protection diesel. Corrective actions included more stringent chemical control of new fuel and biocide addition, in addition to cleaning of the tank.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Chemistry Program Effectiveness Inspection will verify the effectiveness of the chemistry programs in managing the effects of aging or will identify corrective actions, possibly including programmatic enhancement, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.13 Closed Cooling Water Chemistry Program

Program Description

The Closed Cooling Water Chemistry Program will mitigate damage due to loss of material, cracking, and reduction in heat transfer of plant components within the scope of license renewal that contain treated water in a closed cooling water system or component (e.g., heat exchanger) served by or connected to a closed cooling water system. The program manages the relevant conditions (e.g., concentrations of chlorides, fluorides, oxygen, and sulfates) that could lead to the onset and propagation of a loss of material, cracking, or reduction of heat transfer through proper monitoring and control of corrosion inhibitor concentrations consistent with current EPRI closed cooling water chemistry guidelines. The relevant conditions are specific parameters such as sulfates, halogens, dissolved oxygen, and conductivity that could lead to, or are indicative of, conditions for corrosion or SCC of susceptible materials, as well as erosion and fouling. The Closed Cooling Water Chemistry Program is a mitigation program.

The Closed Cooling Water Chemistry Program includes corrosion rate measurement at a select location in the Reactor Closed Cooling Water (RCC) System. The program is supplemented by a separate one-time inspection of representative areas of select closed cooling water systems, as well as components served by or connected to those closed cooling water systems, to provide confirmation that loss of material and cracking are effectively mitigated or to further detect and characterize whether, and to what extent, degradation is occurring. The Closed Cooling Water Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection for managing loss of material and cracking. The Closed Cooling Water Chemistry Program is supplemented by the Heat Exchangers Inspection for managing reduction in heat transfer. The effectiveness inspection and at least one additional measurement of RCC corrosion rates will be performed and evaluated prior to entering the period of extended operation.

NUREG-1801 Consistency

The Closed Cooling Water Chemistry Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M21, "Closed-Cycle Cooling Water System," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Parameters Monitored or Inspected (and Detection of Aging Effects, Monitoring and Trending, and Acceptance Criteria) –**

  The program does not include performance or functional testing for management of loss of material or cracking since performance and functional testing verify that component active functions can be accomplished but, in most cases, provide little definitive information or value with respect to the condition of passive components. In lieu of performance monitoring and functional testing, the Closed Cooling Water Chemistry Program includes measurement of corrosion rates in select RCC System locations and is supplemented by the one-time Chemistry Program Effectiveness Inspection, which includes closed cooling water system locations and heat exchangers served by closed cooling water systems, to confirm adequate mitigation of loss of material and cracking in low flow and stagnant areas. The Closed Cooling Water Chemistry Program is supplemented by the one-time Heat Exchangers Inspection to confirm adequate mitigation of reduction in heat transfer.

Required Enhancements

Prior to the period of extended operation the enhancement listed below will be implemented in the identified program element:

- **Detection of Aging Effects –**

  Ensure that at least one additional RCC corrosion rate measurement is performed and evaluated prior to entering the period of extended operation to provide direct information as to the effectiveness of the chemical treatments. If necessary, based on the results, establish a frequency for subsequent measurements.

Operating Experience

The Closed Cooling Water Chemistry Program is an ongoing program that effectively incorporates EPRI closed cooling water guideline documents as well as "lessons learned" from site and other utility operating experience. The program has been, and continues to be, subject to periodic internal and external assessment of its performance to identify strengths and potential adverse trends. In addition, monthly reports are generated addressing chemistry performance indicators. The February 2008 report identified the parameters for closed cooling water systems; the reactor building closed cooling water, diesel cooling water, and chilled water systems in particular, to be nominal. A November 2004 internal assessment, including industry input, found that the program does an adequate job of maintaining effective chemistry control, with a strength being the aggressiveness in returning out-of-limit parameters to within limits in a timely manner. The assessment found no chemistry control related equipment reliability issues over the scope of the review.

Review of Columbia operating experience did not reveal a loss of component intended function of subject components exposed to closed cooling water that could be attributed to an inadequacy of the Closed Cooling Water Chemistry Program. Furthermore, industry, particularly INPO, operating experience is periodically evaluated by Columbia and incorporated into plant programs. No changes to the Closed Cooling Water Chemistry Program were required as a result of these evaluations.

Review of condition reports (CRs) indicates that abnormal chemistry conditions are identified, evaluated, and corresponding adjustments made to correct the chemistry conditions well before a loss of function would become plausible. Corrosion monitoring probes are also used.

Conclusion

The Closed Cooling Water Chemistry Program will manage loss of material, cracking, and reduction in heat transfer for susceptible components through monitoring and control of the corrosion inhibitor concentrations and relevant parameters in closed cooling water systems and the components that are connected to or served by them. The Closed Cooling Water Chemistry Program, with the required enhancement, and supplemented by the one-time Chemistry Program Effectiveness Inspection and Heat Exchangers Inspection prior to entering the period of extended operation provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.14 Cooling Units Inspection

Program Description

The Cooling Units Inspection is a new one-time inspection that will detect and characterize the material conditions of aluminum, steel, copper alloy, and stainless steel cooling unit components that are exposed to a condensation (internal or external) environment. The Cooling Units Inspection provides direct evidence as to whether, and to what extent, a loss of material due to crevice, galvanic, general, pitting, or microbiologically influenced corrosion, a reduction in heat transfer due to fouling of heat exchanger tubes and fins, or cracking of aluminum components, has occurred or is likely to occur that could result in a loss of intended function.

Implementation of the Cooling Units Inspection will ensure that the pressure boundary integrity and heat transfer capability of susceptible components are maintained consistent with the current licensing basis during the period of extended operation. Implementation of the inspection will also provide assurance (and confirmation) that the structural integrity of susceptible NSR components will be maintained such that spatial interactions (e.g., leakage) will not result in the loss of any safety-related component intended functions during the period of extended operation.

NUREG-1801 Consistency

The Cooling Units Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Cooling Units Inspection detects and characterizes conditions relative to the following subject mechanical components to determine whether, and to what extent, degradation is occurring:
  - Loss of material due to crevice and pitting corrosion, and MIC of stainless steel components exposed to condensation.
  - Loss of material due to crevice, pitting, and galvanic corrosion, cracking due to SCC, and reduction in heat transfer due to fouling of aluminum heat exchanger fins exposed to condensation.

- Loss of material due to crevice, pitting, and galvanic corrosion and reduction in heat transfer due to fouling of copper alloy heat exchanger tubes exposed to condensation.
- Loss of material due to crevice, pitting, galvanic, and general corrosion and MIC for steel components exposed to condensation.

The Cooling Units Inspection focuses on a representative sample population of subject components at susceptible locations to be defined in the implementing documents. The inspections identify symptomatic evidence of cracking, loss of material, or reduction in heat transfer at other susceptible locations within the scope of the inspection due to the similarities in materials and environmental conditions.

- Preventive Actions
  No actions are taken as part of the Cooling Units Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Cooling Units Inspection are wall thickness or visual evidence of degradation, as measures of loss of material and cracking, and visual evidence of fouling as a measure of reduction in heat transfer. Inspections will be performed by qualified personnel using established NDE techniques.

- Detection of Aging Effects
  The Cooling Units Inspection will use a combination of established volumetric (radiographic testing or ultrasonic testing) and visual (VT-1 or VT-3 or equivalent) examination techniques performed by qualified personnel on a sample population of subject components determined by engineering evaluation, to identify evidence of cracking (of aluminum), a loss of material, or fouling, or to confirm a lack thereof.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operation, and the lowest design margins.

  The Cooling Units Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and location if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Cooling Units Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effects. The inspection provides for confirmation of material conditions near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience, documented in recent work orders, revealed that cooling unit coils have been found clean and no leakage was observed.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for components within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Cooling Units Inspection will verify that there are no aging effects requiring management for the subject components, or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation and that spatial interactions (e.g., leakage) will not result in loss of safety-related component intended functions during the period of extended operation.

B.2.15 CRDRL Nozzle Program

Program Description

The CRDRL Nozzle Program manages cracking due to flaw growth of the control rod drive return line (CRDRL) nozzle, safe end, cap, and connecting welds. This program was developed in response to industry events involving the control rod drive return line nozzle. The program includes modifications, mitigation, and inspection.

(a) modification

Columbia has modified the CRDRL by the second option discussed in NUREG-1801, XI.M6, cutting and capping the CRDRL with no alternate return line flow established. The modifications were performed prior to initial startup of the Columbia Unit. Modifications were completed by the vessel Original Equipment Manufacturer (OEM).

Since the modifications were performed prior to initial startup of the Columbia Unit, CRD system functionality was demonstrated by the initial system testing, as described in FSAR Section 14.2. This startup testing and subsequent system operation have demonstrated CRD return flow capacity.

(b) mitigation

Columbia mitigates CRDRL nozzle cracking by maintaining water chemistry in accordance with the current BWRVIP guidelines using the BWR Water Chemistry Program.

(c) inspection

The CRDRL Nozzle Program performs ultrasonic inspection of the nozzle in accordance with ASME Section XI, subsection IWB.

The nozzle to safe end and safe end to cap are category B-J welds and are covered by the Risk Informed ISI Program. In part because of the all low alloy steel construction that is not susceptible to stress corrosion cracking, these are low risk welds and are not scheduled for inspection in the third 10-year interval.

Enhanced ISI / Maintenance Programs are not required as Columbia did not install an alternate return line.NUREG-1801 states that the effects of cracking will also be monitored in accordance with NUREG-0619. For licensees who have cut and capped the CRD return line nozzle with rerouting of the CRD return line, NUREG-0619 requires that during each refueling outage the licensee inspect the welded connection joining the rerouted CRD return line to the system which then returns flow to the reactor vessel. Columbia has used the second option, of not establishing an alternate return line flow, so there is no alternate connection to inspect. This NUREG-0619 requirement is not applicable to Columbia.

Cracking found during inservice inspection is evaluated and dispositioned in accordance with ASME Section XI, subsection IWB. Removing cracks by mechanical means is acceptable per ASME Section XI. However, recent industry practice has been to repair such cracks by weld overlay, in accordance with Code Cases N504-2 and N638. Columbia does not anticipate any indications in their low alloy steel CRDRL nozzle welds; however, should indications be found and repair be required, all available repair techniques would be evaluated. If Columbia opts for a repair technique different from ASME Section XI, a relief request will be submitted for NRC review and approval.

The CRDRL Nozzle Program credits portions of the BWR Water Chemistry Program and the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The CRDRL Nozzle Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M6, "BWR Control Rod Drive Return Line Nozzle."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

Recent License Renewal Applications report that the CRDRL Nozzle Program is effectively managing aging. During RE22 in 2005 the Cooper Nuclear Stations control rod drive return line nozzle inner radius weld and the nozzle-to shell weld were ultrasonically examined and found acceptable. Absence of aging effects indicates that the preventive actions of the program have been effective. The last inspection of the CRDRL stagnant water pipe welds at Duane Arnold Energy Center was performed during Refueling Outage 18. No indications were found in the welds.

Columbia operating experience:

Columbia operating experience is consistent with industry experience and confirms that the CRDRL Nozzle Program is effective in managing cracking of the CRDRL nozzle. Periodic inspections of the CRDRL nozzle, during the second 10-year ISI interval found no cracking. Therefore, continued implementation of the program provides reasonable assurance that the effects of aging will be managed so that the CRDRL nozzle, safe end, cap, and connecting welds will continue to perform their intended function consistent with the current licensing basis during the period of extended operation.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The CRDRL Nozzle Program will manage cracking of the CRDRL nozzle, safe end, cap, and connecting welds. The CRDRL Nozzle Program provides reasonable assurance that cracking will be managed such that the subject components will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

B.2.16 Diesel Starting Air Inspection

Program Description

The Diesel Starting Air Inspection is a new one-time inspection that will detect and characterize the material condition of the air dryers and downstream stainless steel and steel piping and components in the DSA System (excluding the DSA System air receivers). The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred or is likely to occur.

Implementation of the Diesel Starting Air Inspection will provide confirmation that controls on compressed air quality are effective for the DSA System and that the integrity of the air dryers and downstream piping and components (excluding the DSA System air receivers), will be maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Diesel Starting Air Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Diesel Starting Air Inspection includes the air dryers and, conservatively, the downstream stainless steel and steel piping and components in the DSA System (excluding the DSA System air receivers).

  The DSA System is subject to periodic air quality sampling inspections through the Air Quality Sampling Program to verify that the dewpoint is within specified limits. The Diesel Starting Air Inspection will confirm that the controls on moisture content of the air have been effective in ensuring that unacceptable degradation is not occurring in the air dryers and downstream piping and components (excluding the DSA System air receivers).

- Preventive Actions
  No actions are taken as part of the Diesel Starting Air Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Diesel Starting Air Inspection include wall thickness or visual evidence of internal surface degradation, of the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers) as measures of loss of material. Inspections will be performed by qualified personnel using established NDE techniques (i.e., ultrasonic examination). Visual inspection of downstream piping and components for evidence of corrosion and corrosion products may be performed.

- Detection of Aging Effects
  The Diesel Starting Air Inspection will use a combination of established visual examination techniques and non-destructive methods performed by qualified personnel on a sample population of the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers) to identify evidence of any loss of material.

  There are three air dryers in the DSA System. A sample population of these air dryers and the downstream piping and components will be determined by engineering evaluation based on sound statistical sampling methodology. The results of previous inspections will be utilized in consideration of those components most susceptible to degradation. Components will also be evaluated based upon time in service, the severity of conditions during normal plant operation (i.e., the results of the air quality sampling), and design margins.

  The Diesel Starting Air Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  No actions are taken as part of the Diesel Starting Air Inspection to monitor or trend inspection results. This is a one-time inspection activity used to determine if, and to what extent, further actions (including monitoring and trending) may be required.

  Sample size will be determined by engineering evaluation, as described in the *Detection of Aging Effects* element above. Results of the inspection activities that require further evaluation and resolution (e.g., if degradation is detected), will be evaluated using the Columbia corrective action process, including expansion of the sample size and inspection locations to determine the extent of the degradation.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Diesel Starting Air Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The inspection is intended to determine the condition of the DSA System air dryers as well as of the downstream piping and components (excluding the DSA System air receivers), and whether additional controls are required for the period of extended operation.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience reveals that the air receiver tanks have been inspected regularly for indications of loss of material. Relevant operating experience associated with DSA System air receivers is used to identify relevant age related degradation for the DSA System; however, aging of the DSA System air receivers is managed by the Air Quality Sampling Program. Inspection techniques for the air dryers and downstream piping and components will be consistent with accepted industry practices.

  The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for components within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Diesel Starting Air Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions of the DSA System will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.17 Diesel Systems Inspection

Program Description

The Diesel Systems Inspection is a new one-time inspection that will detect and characterize the material condition of the interior of the exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping, and the drain pans and drain piping associated with air-handling units of the Diesel Building HVAC systems. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred or is likely to occur.

Implementation of the Diesel Systems Inspection will provide confirmation that the integrity of the subject components will be maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Diesel Systems Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Diesel Systems Inspection includes the steel exhaust piping exposed to an air-outdoor environment, and the loop seal drains from the exhaust piping that are exposed to a raw water environment, for the following diesel engines:

  - DG-ENG-1A1/1A2
  - DG-ENG-1B1/1B2
  - DG-ENG-1C
  - DSA-ENG-C/2C

  Additionally the stainless steel drain pans and steel drain piping exposed to a raw water environment and associated with the following equipment are in the scope of the Diesel Systems Inspection:

- DMA-AH-11, 12, 21, 22, 31, 32, and 51 (air-handling unit housings)

- Preventive Actions
  No actions are taken as part of the Diesel Systems Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Diesel Systems Inspection include wall thickness or visual evidence of internal surface degradation, of the diesel exhaust piping and the drain pans and drain piping as measures of loss of material. Inspections will be performed by qualified personnel using established NDE techniques (i.e., ultrasonic examination). Visual inspection of the internals for evidence of corrosion and corrosion products may be performed as opportunities for access arise.

- Detection of Aging Effects
  The Diesel Systems Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on a representative sample of the subject components to identify evidence of loss of material.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Diesel Systems Inspection will be conducted after the issuance of the renewed license and prior to the end of the current operating license, with sufficient time to implement programmatic oversight for the period of extended operation. The activities will be conducted no earlier than 10 years prior to the end of the current operating license, so that conditions are more representative of the conditions expected during the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and to determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and locations if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for further monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria. Inspection results will be compared against minimum wall thickness values established in accordance with design requirements or engineering evaluation. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Diesel Systems Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging mechanism is slow acting. The inspection provides for confirmation of material conditions near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has found no indications of loss of material in the subject diesel system components. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for components within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Diesel Systems Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the intended functions of the subject components will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.18 Diesel-Driven Fire Pumps Inspection

Program Description

The Diesel-Driven Fire Pumps Inspection is a new one-time inspection that will detect and characterize the material condition of the interior of the Fire Protection System diesel engine exhaust piping, and of Fire Protection System diesel heat exchangers exposed to a raw water (antifreeze) environment. The inspection provides direct evidence as to whether, and to what extent, a loss of material or reduction in heat transfer has occurred or is likely to occur that could result in a loss of intended function. The inspection also determines whether cracking due to stress corrosion cracking of susceptible materials has occurred. Implementation of the Diesel-Driven Fire Pumps Inspection will ensure that the pressure boundary, structural integrity, and heat transfer capability of susceptible components is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Diesel-Driven Fire Pumps Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Diesel-Driven Fire Pumps Inspection includes the steel exhaust lines that are exposed to an air-outdoor environment and copper alloy, copper alloy > 15% Zn, gray cast iron, and stainless steel heat exchanger components exposed to a raw water (antifreeze) environment for the following diesels:
  - FP-ENG-1
  - FP-ENG-110
- Preventive Actions
  No actions are taken as part of the Diesel-Driven Fire Pumps Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Diesel-Driven Fire Pumps Inspection include: wall thickness or visual evidence of internal surface degradation, of the diesel exhaust piping and heat exchangers as measures of cracking, loss of material, or reduction in heat transfer. Inspections will be performed by qualified personnel using established NDE techniques (i.e., ultrasonic examination). Visual inspection of the internal surfaces for evidence of corrosion, corrosion products, or fouling may be performed.

- Detection of Aging Effects
  The Diesel-Driven Fire Pumps Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on the subject components to identify evidence of loss of material due to corrosion or erosion. In addition, the inspection will determine whether cracking due to stress corrosion cracking of copper alloy > 15% Zn or reduction in heat transfer due to fouling of copper alloy and stainless steel heat exchanger tubes exposed to a raw water (antifreeze) environment is occurring.

  The inspection locations will be determined by engineering evaluation and, where practical, focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and lowest design margins.

  The Diesel-Driven Fire Pumps Inspection activities will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and to determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the number of inspection locations if degradation is detected.

  There are two components in the scope of the inspection (FP-ENG-1 and FP-ENG-110). The inspection locations include the exhaust lines and heat exchanger parts associated with those components. The inspection locations will be determined by engineering evaluation. Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for further monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective

action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Diesel-Driven Fire Pumps Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effects. The activity provides confirmation of conditions where degradation is not expected, has not been observed, or where the aging mechanism is slow acting. The elements comprising the inspection activity are to be consistent with industry practice.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience reveals past issues associated with the subject components, including a loose clamp, a small oil leak, discolored oil, and a damaged connection pipe. None of these issues are age-related, nor do they involve the subject exhaust piping or heat exchanger components.

  The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for components within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Diesel-Driven Fire Pumps Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions of the subject components will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.19 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program

Program Description

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will manage the aging of electrical cables and connections that are not environmentally qualified and are within the scope of license renewal. The program provides for the periodic visual inspection of accessible, non-environmentally qualified electrical cables and connections, in order to determine if age-related degradation is occurring, particularly in plant areas with adverse localized environments caused by high temperatures or high radiation levels. The program will provide reasonable assurance that the electrical components will continue to perform their intended functions for the period of extended operation.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation, and will be repeated every 10 years thereafter.

NUREG-1801 Consistency

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new Columbia program that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program includes all cables and connections (terminal blocks, fuse holders, and electrical penetration assemblies) that are not subject to the EQ requirements of 10 CFR 50.49 and that are within the scope of license renewal. The program is credited with detecting aging effects from adverse localized environments in non-environmentally qualified cables and connections.

  This program is directed by physical location in the plant; because there is no simple way (during an inspection) to determine which components are in scope for license renewal and which are not, the program inspections will be prioritized based on location rather than component identification or function.

Particular attention will be given to the identification of adverse localized environments. The inspection program will define these areas through a review of plant engineering data (EQ records, environmental surveys, etc.) and plant walkdowns.

- Preventive Actions
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is an inspection program; no actions are taken to prevent or mitigate aging degradation. The program is based on visual observation (and detection) only.

- Parameters Monitored or Inspected
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will provide for the visual inspection of accessible cables and connections located in adverse localized environments. The implementing documents for the program will provide the technical basis for the sample selection, with respect to both sample size and inspection locations. Temperature, radiation, and moisture levels will be considered, along with cable insulation material.

  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program focuses on a visual inspection of accessible cables and connections. The cables and connections will not be touched during the inspection (either lifted, separated, felt, or handled in any way). The inspection will record the visible condition of the cable jacket or the visible condition of the connection (splice, terminal block, fuse block, etc.).

- Detection of Aging Effects
  As described above in *Parameters Monitored or Inspected*, the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program provides for a visual inspection of a representative sample of accessible electrical cables and connections located in adverse localized environments. The visual inspections will be performed on a 10-year interval, with the first inspection taking place within the 10-year period prior to the end of the current operating license. The program will inspect the accessible cables and connections for aging effects due to heat, radiation, and moisture, in the presence of oxygen. The visible effects are embrittlement, discoloration, cracking, and surface contamination.

- Monitoring and Trending
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will not include trending actions. If anomalies are found

during the visual inspection process, they will be addressed at that time through the corrective action process.

- Acceptance Criteria
  The inspections of accessible cables and connections will identify unacceptable visual indications of surface anomalies, such as embrittlement, cracking, discoloration, crazing, crumbling, melting, and any other distinct visual evidence of oxidation, material deterioration, or other visible degradation.

  The implementing documents for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will provide specific guidance on the identification of surface degradation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

  In addition, for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Requirements Program, all unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation. The evaluation will consider the age and operating experience of the component, as well as the severity of the anomaly and whether the anomaly has previously been correlated to degradation of the conductor insulation or connections. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, and relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination will be made as to whether the same condition or situation is applicable to other in-scope cables or connections.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new program for which there is no direct site-specific operating experience. Based on review of plant-specific and industry operating

experience, the identified aging effects require management for the period of extended operation.

Plant operating experience has shown that the corrective action program has addressed issues of cable degradation in recent years. Cables have been identified with degraded insulation, primarily as a result of exposure to excessive localized overheating. For example, wiring on an insulated cable associated with the B phase of a motor connection was found to be degraded from overheating, due to the hot connection. Also, wiring to level switches located in the Turbine Building was found to be embrittled as a result of close proximity to hot piping. Cables have also been identified with mechanical damage, such as crimping or pinching (although these are not aging issues). Industry operating experience will be included in the development of this program.

Required Enhancements

Not applicable, this is a new program.

Conclusion

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will manage aging effects due to heat, radiation, and moisture, in the presence of oxygen, for non-environmentally qualified cables and connections. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will provide reasonable assurance that the aging effects will be managed such that the non-environmentally qualified cables and connections subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.20 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program

Program Description

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will detect and identify age-related degradation associated with sensitive, high-voltage, low-current instrumentation cables and connections that are not environmentally qualified and are within the scope of license renewal. This program addresses a subset of the overall in-scope, non-environmentally qualified cable and connection population at Columbia (which is primarily addressed by the program guidelines of the NUREG-1801, Section XI.EI program – see Section B.2.19).

The program applies to in-scope, non-environmentally qualified electrical cables and connections used in circuits with sensitive, high-voltage, low-current signals (such as radiation monitoring and nuclear instrumentation loops). The sensitive nature of these circuits is such that visual inspection alone may not detect degradation to the insulation resistance function of the conductor insulation. This program will provide the technical input necessary to manage the aging of the non-environmentally qualified low-current instrumentation cables and connections within the license renewal scope. The program relies upon a review of calibration records for surveillance tests routinely performed on the circuits to determine if any degradation to the cable system is occurring. Reduced insulation resistance is the parameter of interest. The cables associated with this program at Columbia are not disconnected from their instruments when the present surveillance testing is performed. The program retains the option to perform direct cable testing.

The following instruments are the components within the scope of the program:

- In-Containment Hi Range Radiation Detectors
- Intermediate Range Neutron Monitors
- Local and Average Power Range Neutron Monitors
- Main Steam Line Radiation Detectors
- Reactor Building Exhaust Plenum Radiation Detectors
- Radwaste Building Remote Intake Radiation Detectors
- Standby Service Water Radiation Detectors

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new aging management program that will be implemented prior to the period of extended operation, and will be performed every 10 years thereafter.

NUREG-1801 Consistency

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new Columbia program that will be consistent with the 10 elements of an effective aging management program, as described in NUREG-1801, Section XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is credited with identifying aging effects for sensitive, high-voltage, low-current signal applications that are in-scope for license renewal. These sensitive circuits are potentially subject to reduction in insulation resistance (IR) when found in adverse localized environments.

  The scope of the circuits in the program will be detailed fully in the implementing documents. The scope of the program includes the following components:

  - In-Containment Hi Range Radiation Detectors (connectors) (CMS-RIS-27E/F)
  - Intermediate Range Neutron Monitors (all)
  - Local and Average Power Range Neutron Monitors (all)
  - Main Steam Line Radiation Detectors (MS-RIS-610A/B/C/D)
  - Reactor Building Exhaust Plenum Radiation Detectors (REA-RIS-609A/B/C/D)
  - Radwaste Building Remote Intake Radiation Detectors (WOA-RIS-31A/B, -32A/B)
  - Standby Service Water Radiation Monitors (SW-RIS-604/605)

- Preventive Actions
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program involves a review of calibration records of low-current instruments designed to identify cable (and

connection) degradation; no actions are taken to prevent or mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters monitored (reviewed) by the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program are determined from the specific calibration surveillances. The calibration records (from surveillance testing) of the circuits will be reviewed to determine if there is any indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. The program retains the option to perform direct cable testing of selected circuits.

- Detection of Aging Effects
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will perform a review of the calibration (surveillance testing) records of the cable systems of sensitive, high-voltage, low-current instrumentation circuits to identify indications of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. The initial calibration records review will be conducted prior to the period of extended operation, with subsequent reviews to be conducted at least once every 10 years, with the frequency to be determined by engineering evaluation. The program retains the option to perform direct cable testing of selected circuits. If direct cable testing is performed, it will be a proven cable system test for detecting deterioration of the insulation system (such as insulation resistance testing, time-domain reflectometry testing, or other testing judged to be effective in determining the cable insulation condition). Testing will be conducted at least once every 10 years.

- Monitoring and Trending
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program does not include trending actions as part of the program. The review of calibration test results (or, if used, direct cable testing) that can be trended provides additional information on the rate of degradation.

- Acceptance Criteria
  The acceptance criteria for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will be provided by the implementing documents for the program. Results outside the acceptance criteria will be evaluated in conjunction with the corrective action process. The program will utilize guidance from surveillance test procedures in evaluating the readings (anomalies) that are reviewed.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

  In addition, for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program, corrective actions such as recalibration and circuit trouble-shooting are implemented when calibration or surveillance results do not meet the acceptable criteria. An engineering evaluation is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the electrical cable system can be maintained consistent with the current licensing basis. Such an evaluation will consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective actions required, and the likelihood of recurrence.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new program for which there is no direct site-specific operating experience. Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

  Plant operating experience has shown that the corrective action program has addressed issues of cable degradation in recent years. Cables have been identified with degraded insulation, primarily as a result of exposure to excessive localized overheating. Low-current instrument cable issues have also been identified during loop testing, such as a failed source range monitor cable. An intermediate range monitor cable was found smashed against a ladder (although this is not an insulation resistance aging issue). Industry operating experience will be considered in the development of this program.

Required Enhancements

Not applicable, this is a new program.

Conclusion

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will manage reduction in insulation resistance for non-environmentally qualified cables and connections used in sensitive, high-voltage, low-current circuits. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will provide reasonable assurance that the aging effects will be managed such that the non-environmentally qualified cables and connections used in sensitive, high-voltage, low-current circuits that are subject to aging management review, will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.21 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection

Program Description

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection will detect and identify aging effects for the metallic parts of non-environmentally qualified electrical cable connections within the scope of license renewal.

This inspection will address cable connections that are used to connect cable conductors to other cables or electrical end devices, such as motor terminations, switchgear, motor control centers, bus connections, transformer connections, and passive electrical boxes such as fuse cabinets. The most common types of connections used in nuclear power plants are splices (butt splices or bolted splices), crimp-type ring lugs, connectors, and terminal blocks. Most connections involve insulating material and metallic parts. The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection will focus primarily on bolted connections. This aging management inspection will account for aging stressors such as thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation of the metallic parts. Implementation of this inspection will provide added assurance that the electrical connections in the plant have electrical continuity and are not overheating due to increased resistance. Performance of this inspection will confirm the absence of aging degradation on electrical cable connections.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new aging management activity (a one-time inspection) that will be conducted prior to the period of extended operation.

NUREG-1801 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new one-time inspection that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Detection of Aging Effects –**

  The one-time inspection does not provide for periodic testing (i.e., at least once every 10 years). Because electrical cable connections for many end devices (such as motors, bus connections, and transformers) are inspected (and repaired or remade as necessary) whenever the end device is tested or worked on, and because Columbia has a thermography program that routinely inspects electrical connections throughout the plant (based on current industry practices), a one-time inspection in response to the guidance of NUREG-1801 XI.E6 is adequate. Performance of the inspection will confirm the absence of aging degradation on electrical cable connections.

The technical methodology utilized by the program (thermography augmented by contact resistance tests) is identical to that of NUREG-1801, XI.E6.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The metallic parts of electrical cable connections, not subject to 10 CFR 50.49, and associated with cables that are within the scope of license renewal, are part of this program, regardless of their association with active or passive components.

  The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is applicable to non-environmentally qualified electrical cable connections for the site buildings that are within the scope of license renewal.

- Preventive Actions
  No actions are taken as part of this activity to prevent or mitigate aging degradation.

- Parameters Monitored or Inspected
  This inspection will focus on the metallic parts of electrical cable connections. The inspection will include detection of loosened bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. A representative sample of electrical cable connections will be inspected. The following factors will be considered for sampling: application (high, medium, and low voltage), circuit loading, and physical location (high temperature, high humidity, vibration, etc.) with respect to connection stressors. The technical basis for the sample selected will be documented. If an unacceptable condition or situation is identified in the sample, a determination will be made as to whether the same condition or situation is applicable to other connections.

- Detection of Aging Effects
  A representative sample of the metallic electrical cable connections not subject to 10 CFR 50.49 EQ requirements and within the scope of license renewal will receive a one-time inspection via thermography (augmented with contact resistance testing) prior to the period of extended operation. Thermography is a proven test method for detecting loose connections and degraded connections (i.e., chemical contamination, corrosion, oxidation) leading to increased resistance, and will be

used to test a sample of electrical connections at a variety of plant locations. Thermography can detect aging effects due to thermal cycling, ohmic heating, vibration, and electrical transients. Thermography is an effective tool for inspecting connections that are covered by electrical tape, insulating boots or covers, heat-shrink material, and sleeving. Contact resistance testing of a sample of motor termination connections and other connections will also be utilized.

- Monitoring and Trending
  No actions are taken as part of the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection to monitor or trend inspection results. This is a one-time inspection activity used to determine if, and to what extent, further actions, including monitoring and trending, may be required.

  Sample size will be determined by engineering evaluation, as described for the *Detection of Aging Effects* element above. Results of the inspection activities that require further evaluation and resolution (e.g., if degradation is detected), will be evaluated using the corrective action process, including expansion of the sample size and inspection locations to determine the extent of the degradation.

- Acceptance Criteria
  The acceptance criteria for thermography will be based on the current criteria used for the thermography process at Columbia. The acceptance criteria for the contact resistance tests will be defined in the implementing procedure.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

  In addition, for the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection, an engineering evaluation is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the cable connections can be maintained consistent with the current licensing basis. Such an evaluation will consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective actions necessary, and the likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other in-scope cable connections.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new activity for which there is no site-specific operating experience. Based on review of plant-specific and industry operating experience, the identified aging effects will require inspection to determine the presence (and extent) of any degradation associated with the non-environmentally qualified cable electrical connections.

  Plant operating experience has shown that the corrective action program has addressed issues related to degraded cable connections in recent years. Cable connections have been identified with degraded electrical continuity (i.e., increased resistance), primarily as a result of loosened electrical connections or corrosion. For example, corroded electrical connections were identified in the cooling tower lighting panels (which are not within the scope of license renewal), and an abnormally warm connection on a diesel generator power panel was identified via thermography. Industry operating experience will be included in the development of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection will detect and identify aging issues related to the metallic parts of non-environmentally qualified electrical cable connections. The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection will provide reasonable assurance that aging effects will be identified (and addressed) such that the non-environmentally qualified electrical cable connections subject to aging management review will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

B.2.22 EQ Program

Program Description

The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50, Appendix A, Criterion 4 and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an environmental qualification program be established to demonstrate that electrical components located in harsh plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident, high energy line breaks, or post-LOCA environment) are qualified to perform their safety function in those harsh environments after the effects of aging during service life. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Columbia has established an EQ program for electrical equipment that meets the requirements of 10 CFR 50.49 for electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and the environmental conditions to which the components could be subjected. 10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) and 10 CFR 50.49(l) permit different qualification criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the Division of Operating Reactor (DOR) Guidelines, NUREG-0588, and Regulatory Guide 1.89 Revision 1. Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of inservice aging.

The EQ Program manages component thermal, radiation, and cyclic aging through the use of aging evaluations based on the methods identified in 10 CFR 50.49(f) and NRC Regulatory Guide 1.89 Revision 1. As required by 10 CFR 50.49, components subject to EQ but not qualified for the entire current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for environmentally qualified components that specify a qualification of at least 40 years are identified as TLAAs for license renewal.

The EQ Program, which implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588 and Regulatory Guide 1.89 Revision 1), is an aging management program for license renewal. This existing program is used to manage aging of components in the scope of 10 CFR 50.49 during the current license term and is used routinely to adjust (extend or reduce) qualified life via re-analysis and to determine when replacement or refurbishment is required.

A 40-year administrative limit was placed on qualified life of components in the EQ Program, even when the original EQ analyses indicated a longer qualified life. Prior to entering the period of extended operation, the actual qualified life will be established for those components that were subject to this administrative limit. This actual qualified life will be based on existing analytical methods and data. For those components that do not show a minimum 60-year life after lifting the administrative limit, the EQ Program will ensure qualified life is not exceeded by directing refurbishment, replacement, or re-analysis to extend the qualification.

Re-analysis of an aging evaluation to extend the qualification of components under 10 CFR 50.49(e) is performed on a routine basis as part of the EQ Program. Re-analysis may be applied to environmentally qualified components whose qualified life is less than that of the renewed operating license term. Important attributes for the re-analysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). A complete discussion of the EQ re-analysis attributes is found in Section 4.4 of the Application.

Consistent with NRC guidance provided in Regulatory Issue Summary 2003-09, no additional information is required to address Generic Safety Issue 168, "Environmental Qualification of Electrical Component."

NUREG-1801 Consistency

The EQ Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section X.E1, "Environmental Qualification (EQ) of Electrical Components."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

A formal process for review of industry operating experience is used to identify and transfer lessons learned from industry experience into Columbia processes and programs, including the EQ Program. Plant-specific operating experience is identified and evaluated primarily through the corrective action program. Evaluation of both industry and plant-specific operating experience includes consideration of the need to modify qualification bases and conclusions, including qualified life. The EQ Program is in compliance with 10 CFR 50.49, thereby providing reasonable assurance that the environmentally qualified components will be able to perform their intended functions even at the end of their qualified life.

Selected operating experience that affected the qualified lives of environmentally qualified equipment at Columbia are as follows:

- Lead wires on certain normally energized solenoid valves are required to be replaced periodically (from INPO).
- Normally energized relays have been assigned an operating life based on plant-specific operating experience.
- The orientation of ASCO and Marotta solenoid valves is controlled to prevent excessive heat rise to the electrical components (INPO).
- Replacement of Namco switches on the MSIVs is now based on plant-specific operating experience.
- A Columbia EQ procedure was modified to consider the effect of high float voltages on DC coils (industry EQ group operating experience).

Conclusion

The EQ Program is in compliance with the requirements of 10 CFR 50.49 and is successfully being used to manage the aging of equipment in the program during the current license term. The existing EQ Program will be used to manage aging during the period of extended operation and includes provisions to ensure that the qualification bases are maintained and that components do not exceed their qualified lives. The EQ Program provides reasonable assurance that the effects of aging will be adequately managed and that environmentally qualified components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.23 External Surfaces Monitoring Program

Program Description

The External Surfaces Monitoring Program will manage the following aging effects for the external surfaces, and in some cases the internal surfaces, of mechanical components within the scope of license renewal:

- Loss of material for metals (aluminum, copper alloy, copper alloy > 15% Zn, gray cast iron, stainless steel (including CASS), and steel) that are exposed to condensation, air-indoor uncontrolled, and air-outdoor environments
- Cracking of aluminum and stainless steel exposed to condensation environments
- Hardening and loss of strength for elastomer-based mechanical sealants and flexible connections in HVAC systems

The External Surfaces Monitoring Program is a condition monitoring program that consists of visual inspections and surveillance activities of accessible external surfaces on a frequency that generally exceeds once per fuel cycle. Surfaces that are inaccessible during normal plant operation are inspected during refueling outages. Surfaces that are inaccessible or not readily visible during both plant operations and refueling outages, such as surfaces that are insulated, are inspected opportunistically, for example during maintenance activities during which insulation is removed.

The External Surfaces Monitoring Program is supplemented by the Aboveground Steel Tanks Inspection to manage loss of material for the inaccessible external surfaces of the carbon steel condensate storage tanks (i.e., the tank bottom).

NUREG-1801 Consistency

The External Surfaces Monitoring Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M36, "External Surfaces Monitoring."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope of Program –**
  - Add aluminum, copper alloy, copper alloy >15% Zn, gray cast iron, stainless steel (including CASS), and elastomers to the scope of the program.
  - Add cracking as an aging effect for aluminum and stainless steel components.
  - Add hardening and loss of strength as aging effects for elastomer-based mechanical sealants and flexible connections in HVAC systems.
- **Monitoring and Trending –**
  - Add physical examination techniques in addition to visual inspection to detect hardening and loss of strength for elastomer-based mechanical sealants and flexible connections in HVAC systems.
  - Add visual (VT-1 or equivalent) or volumetric examination techniques to detect cracking.

Operating Experience

The elements that comprise the External Surfaces Monitoring Program are consistent with industry practice and have proven effective in maintaining the material condition of Columbia plant systems and components.

A review of the most recent plant-specific operating experience, through a search of condition reports, revealed that minor component leakage (typically at bolted joints and closures), damage (event-driven, not age-related), and degradation are routinely identified by the External Surfaces Monitoring Program, with subsequent corrective actions taken in a timely manner; and that no loss of pressure boundary integrity has occurred that was, or could have been, attributed to the aging effects that are in the scope of the program.

Operating experience associated with the External Surfaces Monitoring Program is routinely documented and communicated to site personnel in System Health Reports. System Health Reports are updated after significant changes, or at least quarterly.

Conclusion

The External Surfaces Monitoring Program will detect and manage loss of material for aluminum, copper alloy, copper alloy >15% Zn, gray cast iron, stainless steel (including CASS), and steel components. The continued implementation of the External Surfaces Monitoring Program, with the required enhancements, provides reasonable assurance that the effects of aging, including cracking for aluminum and stainless steel components and hardening and loss of strength for elastomer-based mechanical sealants and flexible connections in HVAC systems, will be managed such that components subject to aging management will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.24 Fatigue Monitoring Program

Program Description

The Fatigue Monitoring Program manages fatigue of the reactor pressure vessel by tracking thermal cycles as required by Technical Specification 5.5.5, "Component Cyclic or Transient Limit." The Fatigue Monitoring Program also manages fatigue of other components (including the ASME Class 1 reactor coolant pressure boundary, high energy line break locations, and Primary Containment) by tracking transient cycles. The Fatigue Monitoring Program is a combination of time-limited aging analyses (cumulative usage factor calculations) and transient counting procedures.

The Fatigue Monitoring Program uses the systematic counting of plant transient cycles to ensure that the numbers of analyzed cycles are not exceeded, thereby ensuring that component fatigue usage limits are not exceeded.

The BWR Vessel Internals Program contributes to managing fatigue of the jet pumps by checking the jet pump set screw gaps each outage. If any out of specification gaps are found, Columbia will calculate the additional fatigue accumulated by the jet pumps due to those gaps.

The Fatigue Monitoring Program acceptance criteria are to maintain the number of counted transient cycles below the analyzed number of cycles for each transient. The Columbia program periodically updates the cycle counts. When the accumulated cycles approach the analyzed design cycles, corrective action is required to ensure the analyzed number of cycles is not exceeded. Corrective action may include update of the fatigue usage calculation. Any re-analysis will use an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) to determine a valid CUF.

Columbia has assessed the impact of the reactor coolant environment on the sample of critical components identified in NUREG/CR-6260. These components were evaluated by applying environmental life correction factors to ASME Code fatigue analyses. Formulae for calculating the environmental life correction factors are contained in NUREG/CR-6583 for carbon and low alloy steels and in NUREG/CR-5704 for austenitic stainless steel. The austenitic stainless steel formulae are also applied to nickel alloys. Columbia will enhance the Fatigue Monitoring Program to include the cycles analyzed for the effects of the reactor coolant environment on fatigue prior to the period of extended operation. The enhancement is explained in detail under *Required Enhancements* below.

NUREG-1801 Consistency

The Fatigue Monitoring Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program elements:

- **Preventive Actions, Monitoring and Trending, Acceptance Criteria –**

  Columbia has analyzed the effects of the reactor coolant environment on fatigue for the six locations recommended by NUREG\CR-6260. These analyses are based on the projected cycles for 60 years of operation (plus some conservatism) rather than the original design cycles in FSAR Table 3.9-1. The Fatigue Monitoring Program will be enhanced to ensure that action will be taken when the lowest number of analyzed cycles is approached.

- **Acceptance Criteria –**

  For each location that may exceed a cumulative usage factor (CUF) of 1.0 (due to projected cycles exceeding analyzed, or due to as-yet undiscovered industry issues), the Fatigue Monitoring Program will implement one or more of the following:

  (1) Refine the fatigue analyses to determine valid CUFs less than 1.0.

  This includes refining the analysis to increase accuracy and reduce conservatism. Any re-analysis will use an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) to determine a valid CUF less than 1.0.

  (2) Manage the effects of aging due to fatigue at the affected locations by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC).

  Should Columbia select the option to manage the aging effects due to fatigue, the inspection program will meet the following criteria: (1) the inspection program will be based on the 10 elements for an effective aging management program, as defined in NRC Branch Position RLSB-1, (2) the aging management program will be submitted for NRC review and approval at least two years prior to entering the period of extended operation, and (3) the method of inspection will be based on a qualified volumetric examination technique.

(3) Repair or replace the affected locations before exceeding a CUF of 1.0.

By implementation of one or more of these options, Columbia will manage the aging effect of fatigue for the period of extended operation, with consideration of the effects of the reactor coolant environment on fatigue.

- **Scope –**

  Correlate information relative to fatigue monitoring and provide more definitive verification that the transients monitored and their limits are consistent with or bound the FSAR and the supporting fatigue analyses, including the environmentally-assisted fatigue analyses.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

NRC document RIS 2008-30 dealt with the use of single dimension stress factors in on-line fatigue analyses. Columbia reviewed RIS 2008-30 and determined that no changes were required to the Columbia Fatigue Monitoring Program. Columbia has no on-line fatigue analyses. Columbia's fatigue analyses of record evaluated multi-dimensional stresses and analyzed the dimensions appropriate to each component.

Columbia operating experience:

The three most recent counting of cycles show the systematic implementation of the Fatigue Monitoring Program.

In August 2000, Columbia operated for a period of time with the recirculation pumps in an unbalanced mode (pump speeds different by more than 50%). The effect of that flow on the fatigue usage of the jet pumps was evaluated. Jet pump clamps were installed on all 20 jet pumps during refueling outage R-17 (2005). Each jet pump mixer was clamped to its diffuser to minimize flow induced vibration caused by leakage at the mixer to diffuser slip joint interface. As long as the set screw gaps remain within their revised criteria no additional fatigue due to bypass leakage flow induced vibration is accumulated. Columbia reviewed the latest gap status after the 2007 outage and extended the usage factor to 60 years. The Columbia Fatigue Monitoring Program will continue to monitor both the occurrence of design cycles and the jet pump gaps, effectively managing the fatigue of the jet pumps through the period of extended operation.

Review of the Fatigue Monitoring Program for license renewal identified improvements for the verification that the Columbia cycle counting program included all the fatigue transients identified in the FSAR and fatigue analyses of record, including the environmentally-assisted fatigue analyses. A review of the program and enhancement of the documentation of that correlation were initiated as part of the License Renewal Project.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Fatigue Monitoring Program is in compliance with the requirements of ASME Section III. The Fatigue Monitoring Program will maintain the validity of the fatigue design basis for reactor coolant system components designed to withstand the effects of cyclic loads due to reactor coolant system transients. The Fatigue Monitoring Program will be used to manage aging during the period of extended operation and includes provisions to ensure that the analyzed transients are not exceeded. The Fatigue Monitoring Program provides reasonable assurance that the effects of aging will be adequately managed and that components will continue to perform their intended functions for the period of extended operation.

B.2.25 Fire Protection Program

Program Description

The Fire Protection Program is an existing program that is described in the Fire Protection Evaluation, Appendix F (Section F.5) of the FSAR, and which is credited with managing loss of material, cracking, delamination, separation, and change in material properties for susceptible components in the scope of license renewal that have a fire barrier function. Periodic visual inspections and functional tests are performed of fire dampers, fire barrier walls, ceilings and floors, fire-rated penetration seals, fire wraps, fire proofing, and fire doors to ensure that functionality and operability are maintained. In addition, the Fire Protection Program supplements the Fuel Oil Chemistry Program and External Surfaces Monitoring Program through performance monitoring of the diesel-driven fire pump fuel oil supply components and testing and inspection of the halon suppression system, respectively. The Fire Protection Program is a condition monitoring program, comprised of tests and inspections in accordance with National Fire Protection Association (NFPA) recommendations.

NUREG-1801 Consistency

The Fire Protection Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M26, "Fire Protection," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Scope –**

  A low pressure carbon dioxide (suppression) system automatically provides fire protection for the turbine generator exciter housing, as described in FSAR Section F.2.4.5. However, neither the turbine generator exciter nor the associated carbon dioxide suppression system is in the scope of license renewal. As such, aging management of the carbon dioxide suppression system is not required and the associated facets of the site Fire Protection Program are not credited for license renewal.

- **Parameters Monitored or Inspected, Detection of Aging Effects –**

  Functional tests and inspections of the halon suppression system that are included in the Fire Protection Program are performed at an interval greater than biannually, which has been demonstrated to be adequate, based on the absence of any related problems as reported through the corrective action program.

- **Scope, Acceptance Criteria –**

  The Fire Protection Program does not include specific confirmation of "no degradation in the fuel oil supply line for the diesel-driven fire pump." Rather, degradation noted for fuel oil supply components during periodic performance testing of the diesel-driven fire pumps through the Fire Protection Program, if any, is evaluated prior to loss of intended function. In addition, the Chemistry Program Effectiveness Inspection characterizes the internal surface condition of the fuel oil supply line (tubing) for confirmation of the effectiveness of the Fuel Oil Chemistry Program.

Required Enhancements

None.

Operating Experience

A review of fire barrier, essential fire-rated penetration seal, fire wrap, fireproofing, fire door, diesel-driven fire pumps, and halon suppression system inspections previously conducted at Columbia confirms the reasonableness and acceptability of the inspections and their frequency in that degradation of the subject components, although unrelated to aging, was detected prior to loss of function. These inspections have not found any age-related problems.

The NRC presently conducts triennial fire protection team inspections at the Columbia site to assess whether an adequate fire protection program has been implemented and maintained. The most recent of these inspections was conducted in March of 2006 and is documented in Inspection Report 2006-008 for Docket 50-397. This inspection identified one non-significant, non-cited violation (related to electrical circuit vulnerabilities and deferred to allow industry evaluation of the issue), one finding of very low safety significance (related to multiple "hot" shorts in Reactor Protection System circuitry), and one unresolved item that was not related to the portions of the program credited for aging management. The inspection team verified that fire protection-related issues are entered into the corrective action program at an appropriate threshold for evaluation. The inspection team also reviewed the program for implementing compensatory measures in place for out-of-service, degraded, or inoperable fire protection, with no findings identified. The inspection provided verification that manual and automatic detection systems were installed, tested, and maintained in accordance with the NFPA code of record. The inspection team evaluated the adequacy of fire area barriers, penetration seals, fire doors, fire wraps, and fire-rated electrical cables. The team observed the material condition and configuration of the installed barriers, seals, doors, and cables.

In addition, the team reviewed licensee documentation, such as NRC safety evaluation reports, and deviations from NRC regulations and the NFPA codes to verify that fire protection features met license commitments. No findings of significance were found. Additionally, a past triennial NRC inspection of the Fire Protection Program, conducted in March-April of 2003 and documented in Inspection Report 50-397/2003-002, identified the same electrical circuit vulnerabilities that were deferred to allow industry evaluation and resolution, and are not related to the portions of the program credited with aging management. Otherwise, the conclusions of the 2003 inspection were similar to the results of the 2006 inspection.

No NRC concerns or Columbia management concerns (through periodic audits, self-assessments, and health reports) were identified with respect to inspection, testing, and maintenance of the Fire Protection System.

A search was performed of condition reports for the Fire Protection System. When conditions were found that required correction, they were evaluated in accordance with the corrective action program. Examples include degraded Darmatt fire barriers that were found during periodic surveillance activities and repaired. This review identified minor issues that did not affect the effectiveness of the Fire Protection Program or the aging effects under evaluation.

Conclusion

The Fire Protection Program will detect and manage loss of material, cracking, delamination, separation, and change in material properties for susceptible components. The Fire Protection Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.26 Fire Water Program

Program Description

The Fire Water Program (sub-program of the overall Fire Protection Program) is an existing program that is described in the Fire Protection Evaluation, Appendix F (Section F.5) of the FSAR, and which is credited with aging management of the water-based fire suppression components in the scope of license renewal.

The Fire Water Program will manage loss of material due to corrosion, erosion, and macrofouling for all susceptible materials in the Fire Protection System, including water supply components, which are exposed to raw water. The program will also manage cracking due to SCC/IGA of copper alloy > 15% Zn components exposed to raw water.

The Fire Water Program will manage loss of material due to selective leaching for the copper alloy > 15% Zn spray nozzles that are part of a wet-pipe sprinkler configuration that are exposed to raw water. The Selective Leaching Inspection will manage loss of material due to selective leaching of susceptible components other than the wet-pipe spray nozzles.

The Fire Water Program is applicable to a variety of materials, including carbon steel, gray cast iron, copper alloy, copper alloy > 15% Zn and stainless steel, for piping and piping components such as valve bodies, tubing, strainer bodies, standpipes (piping), sprinklers (spray nozzles), pump casings, orifices, and hydrants.

Periodic inspection and testing of water-based fire suppression systems provides reasonable assurance that the systems will remain capable of performing their intended function. Periodic inspection and testing activities include hydrant and hose station inspections, flushing, flow tests, and spray and sprinkler system inspections. The Fire Water Program is a condition monitoring program, comprised of tests and inspections generally in accordance with NFPA recommendations.

Following receipt of the renewed license, and prior to the period of extended operation, the Fire Water Program will be enhanced to incorporate sprinkler head sampling or replacements, in accordance with NFPA 25, and either ultrasonic testing or internal visual inspection of representative above ground portions of water suppression piping that are exposed to water.

NUREG-1801 Consistency

The Fire Water Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M27, "Fire Water System."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Parameters Monitored or Inspected, Detection of Aging Effects –**

  Perform either ultrasonic testing or internal visual inspection of representative portions of above ground fire protection piping that are exposed to water, but do not normally experience flow, after the issuance of the renewed license, but prior to the end of the current operating term and at reasonable intervals thereafter, based on engineering review of the results.

- **Detection of Aging Effects –**

  Either replace sprinkler heads that have been in place for 50 years or submit representative samples to a recognized laboratory for field service testing in accordance with NFPA 25 recommendations. Perform subsequent replacement or field service testing of representative samples at 10-year intervals thereafter or until there are no sprinkler heads installed that will reach 50 years of service life during the period of extended operation.

- **Acceptance Criteria –**

  Perform hardness testing (or equivalent) of the sprinkler heads as part of their NFPA sampling, to determine whether loss of material due to selective leaching is occurring.

Operating Experience

Water-suppression portions (subsystems) of the Fire Protection System are inspected, tested, and maintained following NFPA recommendations and at the intervals recommended by the corresponding NFPA standards, or as evaluated and adjusted by Columbia. With one exception (a water hammer event in 1998 that led to a fire protection system valve rupture and subsequent flooding), the water-suppression systems have demonstrated reliable performance with no significant problems in the approximate 20 years since their installation. The water hammer issue (and valve failure) was not age-related.

The NRC presently conducts triennial fire protection team inspections at the Columbia site to assess whether an adequate fire protection program has been implemented and maintained. The most recent of these inspections was conducted in March of 2006 and is documented in Inspection Report 2006-008 for Docket 50-397. This inspection identified one non-significant, non-cited violation (related to electrical circuit vulnerabilities and deferred to allow industry evaluation of the issue), one finding of very low safety significance (related to multiple "hot" shorts in Reactor Protection System circuitry), and one unresolved item that were not related to the portions of the program credited for aging management. The inspection team verified that fire protection-related issues are entered into the corrective action program at an appropriate threshold for evaluation. With respect to fire suppression, the inspection team evaluated the adequacy of fire suppression and detection systems, including observation of the material condition and configuration of the installed fire suppression systems, with no findings identified. The inspection team also reviewed the program for implementing compensatory measures in place for out-of-service, degraded, or inoperable fire protection, with no findings identified. The inspection provided verification that manual and automatic detection systems were installed, tested, and maintained in accordance with the NFPA code of record. Additionally, a past triennial NRC inspection of the Fire Protection Program (including the Fire Water Program), conducted in March-April of 2003 and documented in Inspection Report No. 50-397/2003-002, identified the same electrical circuit vulnerabilities that were deferred to allow industry evaluation and resolution, and are not related to the portions of the program credited with aging management. Otherwise, the conclusions of the 2003 inspection were similar to the results of the 2006 inspection.

No NRC concerns or Columbia management concerns (through periodic audits, self-assessments, and heath reports) were identified with respect to inspection, testing, and maintenance of water-suppression portions of the Fire Protection System.

A search was performed of condition reports for the Fire Protection System. When conditions were found that required correction, they were evaluated in accordance with the corrective action program. A sampling of data forms for recording the results of the credited surveillance and test procedures were reviewed for recent monthly, semiannual, annual, and refueling interval inspections, flushes, and flow tests. Data forms for surveillances and tests that have a periodicity of every three years were also reviewed to cover the two most recent surveillances. Any deviations from the acceptance criteria were evaluated and corrected in accordance with the corrective action program. This review identified only minor issues not related to the effectiveness of the Fire Water Program or the aging effects under evaluation.

Conclusion

The Fire Water Program will detect and manage loss of material, as well as fouling, for susceptible components. The Fire Water Program, with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.27 Flexible Connection Inspection

Program Description

The Flexible Connection Inspection is a new one-time inspection that will detect and characterize the material condition of elastomer components that are exposed to treated water, dried air, gas, and indoor air environments. The inspection provides direct evidence as to whether, and to what extent, hardening and loss of strength due to thermal exposure and ionizing radiation has occurred or is likely to occur that could result in a loss of intended function of the elastomer components.

Implementation of the Flexible Connection Inspection will ensure that the pressure boundary integrity of susceptible components is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Flexible Connection Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection," with exceptions.

Exceptions to NUREG-1801

Program Elements Affected:

- **Parameters Monitored or Inspected, Detection of Aging Effects –**

  In addition to visual examination techniques, the Flexible Connection Inspection will include physical examination techniques, such as physical manipulation and prodding.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  A representative sample of components at susceptible locations will be examined for evidence of hardening and loss of strength (due to thermal exposure and ionizing radiation), or to confirm a lack thereof.

  The Flexible Connection Inspection focuses on a limited but representative sample population of subject components at susceptible locations to be defined in the implementing documents, to include internal and external surfaces of flexible connections exposed to treated water, dried air, gas, and indoor air environments. The inspections performed will be used to provide symptomatic evidence of hardening and loss of strength at the other susceptible, but possibly inaccessible, locations due to the similarities in materials and environmental conditions.

- Preventive Actions
  No actions are taken as part of the Flexible Connection Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Flexible Connection Inspection include visual evidence of surface degradation, such as cracking or discoloration, as well as physical manipulation and prodding, as measures of hardening and loss of strength. Inspections will be performed by qualified personnel using established techniques, such as NDE, consistent with the requirements of 10 CFR 50 Appendix B.

- Detection of Aging Effects
  The Flexible Connection Inspection will use established visual examination techniques (such as equivalent to VT-1 or VT-3), as well as physical manipulation, performed by qualified personnel on a sample population of subject components to identify evidence of hardening and loss of strength.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Flexible Connection Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and location if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective

action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Flexible Connection Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging mechanism is slow acting.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has identified no issues for the flexible connections in the systems within the scope of this inspection. However, tears have been found in several suction and discharge boots (flexible connections) on air-handling units of the HVAC systems. The tears were attributed to normal operational wear; the boots remained pliable (i.e., no hardening) and no operability issues were identified. These flexible connections are included in the scope of the External Surfaces Monitoring Program.

  The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for systems within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Flexible Connection Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions of the subject components will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.28 Flow-Accelerated Corrosion (FAC) Program

Program Description

The Flow-Accelerated Corrosion (FAC) Program will manage loss of material for steel and gray cast iron components located in the treated water environment (including steam, reactor coolant, closed cycle cooling water > 60C (140F), and treated water > 60C (140F)) of systems that are susceptible to flow-accelerated corrosion (FAC), also called erosion-corrosion.

The FAC Program is a condition monitoring program that ensures the integrity of piping systems susceptible to FAC is maintained. The program was developed in response to NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," and NRC GL 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning." The program follows the guidance and recommendations of EPRI NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," and combines the elements of predictive analysis, inspections (to baseline and monitor wall-thinning), industry experience, station information gathering and communication, and engineering judgment to monitor and predict FAC wear rates.

NUREG-1801 Consistency

The FAC Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M17, "Flow-Accelerated Corrosion."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope –**

  Add the Containment Nitrogen System components supplied with steam from the Auxiliary Steam System to the scope of the program.

  Add gray cast iron as a material identified as susceptible to FAC.

Operating Experience

The FAC Program is an ongoing program that has implemented the recommended actions of GL 89-08. The health of the program and corresponding systems are periodically reported, including material conditions. Industry operating experience has been, and continues to be, evaluated for impact to Columbia and for possible program enhancement. For example, based on review of INPO operating experience 14865, the program was enhanced to require evaluation of replacements for future inspection.

Periodic self assessments are also conducted. Gaps identified during the most recent self assessment have all been closed; and the FAC program plan was recently updated, with the current revision addressing all issues identified by the self assessment. In the last benchmark assessment, performed in March 2007, no issues or weaknesses were identified.

As a result, Columbia has programs and procedures in place, with operating experience demonstrating that the FAC Program is capable of detecting and managing loss of material due to FAC for susceptible components, and will continue to be an effective aging management program for the period of extended operation.

A review of program health reports, recent self-assessment reports, and related condition reports, demonstrates that the FAC Program is effective in detecting loss of material due to FAC for susceptible components, and defining the corrective actions (e.g., repair or replacement) necessary to assure their continued operation in accordance with design requirements.

Conclusion

The FAC Program will detect and manage loss of material due to FAC for susceptible components. The FAC Program, with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.29 Fuel Oil Chemistry Program

Program Description

The Fuel Oil Chemistry Program will mitigate the effects of aging for the storage tanks and associated components containing fuel oil that are within the scope of license renewal by verifying and maintaining the quality of the fuel oil used in the emergency diesel generators and the diesel-driven fire pumps. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to corrosion, or cracking due to SCC of susceptible copper alloys. through proper monitoring and control of fuel oil contamination consistent with plant Technical Specifications and American Society for Testing and Materials (ASTM) standards for fuel oil. The relevant conditions are specific contaminants such as water or microbiological organisms in the fuel oil that could lead to corrosion of susceptible materials. Exposure to these contaminants is minimized by verifying the quality of new fuel oil before it enters the storage tanks and by periodic sampling to ensure the tanks are free of water and particulates. The Fuel Oil Chemistry Program is a mitigation program.

The Fuel Oil Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection, which is a separate one-time inspection of representative areas of the diesel fuel oil system, such as low points where contaminants could accumulate. The one-time inspection provides further confirmation that loss of material, as well as cracking of susceptible copper alloys, is effectively mitigated or to detect and characterize whether, and to what extent, degradation is occurring.

NUREG-1801 Consistency

The Fuel Oil Chemistry Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M30, “Fuel Oil Chemistry,” with exceptions.

Exceptions to NUREG-1801

<u>Program Elements Affected:</u>

- **Scope –**

  The program does not include sampling or testing of new fuel for the diesel-driven fire pumps. Following the guidelines of ASTM standards, stored fuel is periodically sampled and tested.

- **Preventive Actions –**

  Preventive actions do not include the addition of biocides, stabilizers, or corrosion inhibitors to the fuel oil for the emergency diesel generators. The combination of ensuring the specified physical and chemical properties of new fuel oil, and periodic cleaning and draining of the storage tanks mitigates corrosion inside the tanks.

- **Parameters Monitored and Inspected –**

  The program does not include testing of the fuel oil used for the diesel-driven fire pumps for particulates. Sampling in accordance with ASTM standards D1796 and D4057 has proven adequate, based on the absence of related problems reported through the corrective action program.

- **Detection of Aging Effects –**

  Multi-level sampling of the fuel oil storage tanks is not performed; rather, a representative fuel stream sample is drawn from the flushing line during recirculation and transfer, consistent with ASTM D2276-93, step 4.3, laboratory filtration method.

Required Enhancements

None.

Operating Experience

The Fuel Oil Chemistry Program is an ongoing program that effectively incorporates the best practices and industry experience in controlling contaminant levels in fuel oil to minimize degradation. No instances of fuel oil system component failure due to contamination have been identified at Columbia.

With respect to the fuel oil tanks for the emergency diesel generators, review of Columbia operating experience reveals that the Fuel Oil Chemistry Program is adequately preventing a loss of component function of subject components that contain fuel oil. Fuel oil delivered to the site is sampled and analyzed prior to addition to the fuel oil storage tanks for the emergency diesel generators. Stored fuel oil is periodically sampled and analyzed for both the emergency and fire protection diesel generators. Water is removed from the stored fuel oil and particulates are filtered. In addition, visual and ultrasonic inspection of an emergency diesel generator fuel oil storage tank, as listed in FSAR Section 9.5.4.4.a, revealed acceptable conditions for the tank internal surfaces; that is, only light corrosion in previously identified areas with no material loss or obvious changes to the condition of the tank.

The fuel oil tanks for the diesel-driven fire pumps are also periodically sampled and analyzed. Water is removed and particulates are filtered based on condition (e.g., when unacceptable levels during periodic sampling necessitate cleaning of the fuel oil). Review of Columbia operating experience reveals that the Fuel Oil Chemistry Program is adequately preventing a loss of component function of subject components that contain fuel oil. Quarterly sampling of the fuel oil tanks for the diesel-driven fire pumps has been effective at identifying unacceptable levels of water and sediment prior to a loss of function. Higher than expected amounts of water or sediment during periodic sampling has resulted in cleaning of the tanks and filtering of the fuel to restore acceptable conditions. The periodic cleaning and filtering has included the addition of a biocide due to evidence of biofouling.

To meet new Environmental Protection Agency requirements, Columbia will be transitioning to Ultra-Low-Sulfur Diesel (ULSD) fuel prior to the period of extended operation. ULSD fuel and its possible adverse impacts on diesel performance are addressed in NRC Information Notice 2006-022. The impact of using ULSD fuel on the Columbia design and licensing basis has been evaluated, including the consideration of related operating experience from the industry, and corrective actions assigned to account for the future transition. Columbia will provide notification of any changes to the Fuel Oil Chemistry Program as a result of the transition to ULSD fuel.

Conclusion

The Fuel Oil Chemistry Program will manage loss of material and cracking for susceptible components through monitoring and control of contaminants in the fuel oil. The Fuel Oil Chemistry Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.30 Heat Exchangers Inspection

Program Description

The Heat Exchangers Inspection is a new one-time inspection that will detect and characterize the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to indoor air or to water with the chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a reduction of heat transfer due to fouling has occurred or is likely to occur on the heat transfer surfaces of heat exchangers and coolers.

Implementation of the Heat Exchangers Inspection will provide assurance (and confirmation) that the heat transfer capabilities of heat exchangers and coolers in the scope of the inspection will be maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Heat Exchangers Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Heat Exchangers Inspection includes measures to verify that unacceptable reduction in heat transfer is not occurring for the stainless steel and copper alloy heat transfer surfaces of the following heat exchangers and coolers that are in the scope of license renewal, but are not cooled by raw water:

  - Diesel Cooling Water (DCW) lube oil coolers and jacket water heat exchangers
  - Diesel (Engine) Exhaust (DE) turbocharger aftercooler
  - Diesel Lubricating Oil (DLO) lube oil cooler
  - Fuel Pool Cooling (FPC) heat exchangers
  - Reactor Core Isolation Cooling (RCIC) lube oil cooler

- Residual Heat Removal (RHR) heat exchanger
- RHR pump seal coolers
- Reactor Recirculation (RRC) pump seal coolers
- Radwaste Building Mixed Air (WMA) heat exchangers

A representative sample of heat exchanger and cooler surfaces that are exposed to treated water, closed cooling water, and indoor air will be examined for evidence of a reduction in heat transfer capabilities due to fouling, or to confirm a lack thereof, with engineering evaluation of the results.

- Preventive Actions
  No actions are taken as part of the Heat Exchangers Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Heat Exchangers Inspection include visual or volumetric evidence of surface fouling as a measure of reduction in heat transfer capabilities. Inspections will be performed by qualified personnel using established NDE techniques.

- Detection of Aging Effects
  The Heat Exchangers Inspection will use visual examination techniques (VT-3 or equivalent) performed by qualified personnel on a sample population of the heat exchangers and coolers within the scope of the inspection to identify evidence of fouling on heat transfer surfaces, or to confirm a lack thereof.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and the lowest design margins with respect to heat transfer.

  The Heat Exchangers Inspection activities will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes increasing the inspection sample size and location if degradation is detected.

  Sample size will be determined by engineering evaluation of the materials of construction, environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins).

Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Heat Exchangers Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has identified no issues for the heat exchangers in the systems within the scope of this inspection. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for systems within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Heat Exchangers Inspection will verify that reduction in heat transfer does not require management for the subject components, or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.31 High-Voltage Porcelain Insulators Aging Management Program

Program Description

The High-Voltage Porcelain Insulators Aging Management Program will manage the build-up of contamination (hard water residue) deposited on the in-scope high-voltage insulators in the transformer yard by the vapor plume from the Circulating Water System cooling towers. This residue, in conjunction with unfavorable weather conditions (moisture from the plume and freezing temperatures), has caused electrical flashovers on the 500-kV bus pedestal insulators in the transformer yard.

The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program consisting of activities to mitigate potential degradation of the insulation function due to hard water deposits.

Note: There are no station post insulators in the 230-kV system located in the transformer yard.

NUREG-1801 Consistency

The High-Voltage Porcelain Insulators Aging Management Program is an existing Columbia program that is plant-specific. There is no corresponding aging management program described in NUREG-1801, therefore, the program elements are compared to the elements listed in Table A.1-1 of NUREG-1800.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The High-Voltage Porcelain Insulators Aging Management Program is credited for managing the build-up of hard water residue on the in-scope high-voltage insulators (located in the transformer yard) deposited by the vapor plume from the Circulating Water System cooling towers.

  The High-Voltage Porcelain Insulators Aging Management Program involves the following equipment:

  - The high-voltage station post insulators between the 115-kV backup transformer (E-TR-B) and circuit breaker E-CB-TRB.

  The 500-kV insulators, which experienced the flashover events in the past, are not within the scope of license renewal.

- Preventive Actions
  The actions of the High-Voltage Porcelain Insulators Aging Management Program are a preventive maintenance activity that mitigates (retards) degradation of the insulation function.

  The High Voltage Porcelain Insulators Aging Management Program provides for either the periodic coating or cleaning of the applicable high-voltage insulators. Cleaning every two years is performed to prevent the build-up of hard water residue on the insulator surface to a point that could cause an electrical flashover. Coating every 10 years prevents the harmful effect of a hard water residue build-up on the insulators. Cleaning is not required if the insulator is coated.

- Parameters Monitored or Inspected
  The High-Voltage Porcelain Insulators Aging Management Program visually inspects coated insulators every two years for damage. Uncoated insulators are inspected every two years for any unusual conditions.

- Detection of Aging Effects
  The High-Voltage Porcelain Insulators Aging Management Program is a preventative maintenance program that does not have any specific steps to detect hard water residue on the insulators leading to flashover. The program assumes that the residue exists and takes steps to limit its effect (via coating) or to remove it (via cleaning). A visual inspection of the insulator is specified to note any excessive degradation or excessive surface contamination. The in-scope insulators are inspected and cleaned every two years. Cleaning is not required if the insulators are coated. If insulators are coated, the coating is performed every 10 years.

- Monitoring and Trending
  The High-Voltage Porcelain Insulators Aging Management Program does not include trending actions. The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program that is performed at established intervals to coat or clean the in-scope insulators. If during the inspection of the coating or in preparation for cleaning uncoated high-voltage porcelain insulators, significant or unusual or unexpected hard water residue build-up is noted (i.e., excessive deposits), the inspection results will be evaluated through the corrective action program. The corrective action evaluation may result in analysis or further inspection, and a disposition is generated. This disposition may result in a change in the frequency of inspection.

- Acceptance Criteria
  The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance activity that is periodically performed on specific in-scope equipment. There are no defined acceptance criteria; hard water deposits are assumed to occur and the activity is designed to limit their impact on the insulators. For the visual

inspection of the insulators, excessive surface contamination that does not wash off (i.e., obvious degradation on the insulator) is unacceptable. Such degradation is not expected to be seen on the porcelain material.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The elements that comprise the High-Voltage Porcelain Insulators Aging Management Program are consistent with industry practice and have proven effective in maintaining the high-voltage porcelain insulators free from the adverse effects of hard water residue build-up.

  A review of the most recent operating experience for the high-voltage porcelain insulator inspections reveals that the inspections are performed in accordance with procedure, the results are documented and retrievable, and if any abnormalities are identified during inspection, corrective actions are taken. A review of plant-specific operating experience for the most recent five-year period, through a search of condition reports, revealed that no 115-kV or 230-kV output breakers tripped as a result of high currents created when a porcelain insulator in the transformer yard shorted to ground.

  The incidents which alerted the plant to the hard water deposition on the 500-kV insulators are described in Licensee Event Reports 89-002-00 and 90-031. It is noted that these events occurred almost 20 years ago. There is industry operating experience of similar flashover events occurring at plants on the ocean affected by salt spray (Brunswick, Crystal River 3, and Pilgrim), and also plants affected by heavy fog and contamination deposits on high-voltage insulators (River Bend).

Required Enhancements

None.

Conclusion

The High-Voltage Porcelain Insulators Aging Management Program will manage the hard water residue build-up on the in-scope high-voltage insulators in the transformer yard. The continued implementation of the High-Voltage Porcelain Insulators Aging Management Program provides reasonable assurance that the effects of aging will be managed such that components subject to aging management will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.32 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

Program Description

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will manage the aging of inaccessible medium-voltage electrical cables that are not environmentally qualified and subject to wetting within the scope of license renewal. The program provides for the periodic testing of non-environmentally qualified inaccessible medium-voltage electrical cables, in order to determine if age-related degradation is occurring, and includes a provision for the inspection of associated manholes to identify any collection of water. The program will provide reasonable assurance that the electrical components will continue to perform their intended functions for the period of extended operation.

Energized medium-voltage cables (defined as 2kV to 35kV) that are exposed to wetting (standing water or condensation) in inaccessible locations are vulnerable to loss of dielectric strength and a degradation mechanism known as water treeing. The formation of water trees (gradients or tracks in the insulation) can lead to electrical failure. An inaccessible location may be a conduit, a cable trench, a duct bank, an underground vault, or a direct-buried installation.

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation, with the cable testing portion to be performed every 10 years thereafter, and the manhole inspection portion to be performed at least every two years thereafter.

NUREG-1801 Consistency

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new Columbia program that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program involves two parts: first, the actions to inspect the plant manholes (and to drain them, if necessary) on a periodic basis; and second, the development of a testing program to confirm that the conductor insulation on the cables is not degrading.

  This program applies to medium-voltage cables within the scope of license renewal that meet the criteria of an inaccessible location, exposure to wetting, and exposure to significant voltage. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cables in standing water). Periodic exposure to moisture that lasts less than a few days (i.e., normal rain and drain) is not significant. Significant voltage exposure is defined as being subject to system voltage for more than twenty-five percent of the time.

- Preventive Actions
  The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will include periodic preventive actions to inspect for water collection in electrical manholes, and to remove water (as necessary).

- Parameters Monitored or Inspected
  The specific type of test to be utilized in the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will be determined prior to the initial test. The implementing documents will specify a proven test (such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2) for detecting the deterioration of the insulation system due to wetting (and energization), and will reflect the actual test methodology prior to the initial performance of the cable testing. In addition, the provisions for inspecting and draining (if necessary) the electrical manholes will be described in the implementing documents.

- Detection of Aging Effects
  The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will provide for the testing of in-scope medium-voltage cables to detect degradation of the conductor insulation. The program will utilize a proven test for detecting deterioration of the cable insulation due to wetting (and energization). The program will also conduct inspections of the electrical manholes to detect water collection and to drain the manholes (if necessary).

  The cable testing will be performed at least once every 10 years, with the first test to occur during the 10-year period prior to the end of the current operating license. The inspections for water collection will be performed based on actual plant operating experience with water accumulation in the manholes. However, the inspection frequency will be at least once every two years. The first inspections will occur during the 10-year period prior to the end of the current operating license.

- Monitoring and Trending
The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will not include trending actions. If anomalies are found during the testing, they will be addressed at that time under the corrective action program. The results of the manhole inspections will be recorded such that increasing water levels, or the need for more frequent performance of draining, can be identified.

- Acceptance Criteria
The acceptance criteria for each test in the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will be defined by the specific type of test to be performed. The type of test will be determined prior to the initial utilization of the program. The implementing documents will contain specific information on the acceptance criteria for each test.

- Corrective Actions
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

  In addition, for the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program, an engineering evaluation is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the electrical cables can be maintained consistent with the current licensing basis. Such an evaluation will consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective actions required, and the likelihood of recurrence. When an unacceptable condition or situation is identified, a determination will be made as to whether the same condition or situation is applicable to other inaccessible, in-scope medium-voltage cables.

- Confirmation Process
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new program for which there is no site-specific operating experience. Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

  Plant operating experience has shown that the corrective action program has addressed issues of cable degradation in recent years. Control cables, instrument cables, and low-voltage power cables have been identified with degraded insulation, primarily as a result of exposure to excessive localized overheating. There have been no failures of cables directly attributed to water treeing. Columbia has not experienced any degradation failures of medium-voltage cables. However, two 480-V power cables have failed due to damage incurred during installation and subsequent moisture intrusion. One medium-voltage cable failed because it exceeded its ampacity rating.

  Recent inspections of medium-voltage manholes identified two manholes adjacent to the cooling towers with standing water. The source of water has not been determined. This is a current licensing basis issue, and the corrective action program will be used to determine the source, to correct or mitigate the problem, and to determine the future inspection frequency needed based on the cause and the corrective actions taken. A search of plant operating experience identified no other cases of medium-voltage manholes having water intrusion. Industry operating experience will be considered in the development of this program.

Required Enhancements

Not applicable, this is a new program.

Conclusion

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will manage degradation of conductor insulation for inaccessible, non-environmentally qualified medium-voltage cables. The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will provide reasonable assurance that the aging effects will be managed such that the inaccessible, non-environmentally qualified medium-voltage cables subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.33 Inservice Inspection (ISI) Program

Program Description

The Inservice Inspection (ISI) Program manages cracking due to SCC/IGA and flaw growth of reactor coolant system pressure boundary components made of nickel alloy, stainless steel (including cast austenitic stainless steel), and steel (including steel with stainless steel cladding), including the reactor vessel, a limited number of internals components, and the reactor coolant system pressure boundary. The Inservice Inspection (ISI) Program also manages loss of material due to corrosion for reactor vessel internals components and reduction of fracture toughness due to thermal embrittlement of cast austenitic stainless steel pump casings and valve bodies.

The Columbia Inservice Inspection (ISI) Program meets the requirements of ASME Section XI. The Columbia Inservice Inspection (ISI) Program details the requirements for the examination, testing, repair, and replacement of components specified in ASME Section XI for Class 1, 2, or 3 components. The Columbia Inservice Inspection (ISI) Program complies with the ASME Code requirements, and is therefore consistent with the NUREG-1801 program. The program is described in FSAR Section 5.2.4 and is implemented by various plant procedures.

The Columbia program scope has been augmented to include additional requirements, and components, beyond the ASME requirements. Examples include the augmentation of ISI to expanded reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, and examinations per Generic Letter 88-01. Such augmentation is consistent with the ISI program description in NUREG-1801, Section XI.M1.

The Columbia Inservice Inspection (ISI) Program contains a Risk-Informed Inservice Inspection (RI-ISI) program for Class 1 piping, based on EPRI Topical Report TR-112657 Revision B-A, which has been approved by the NRC staff. The RI-ISI provides alternate inspection requirements for a subset of Class 1 piping welds. The staff's review of the RI-ISI program for the third ISI 10-year interval concluded that the program is an acceptable alternative to the current ISI program based on the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI requirements for Class 1, non-socket Category B-J welds. While this varies from the ASME Code, it represents a modernization of the Code that has been accepted by the NRC for use at many nuclear power plants, including Columbia. Because of the widespread NRC acceptance of Risk-Informed ISI, this is not considered an exception to NUREG-1801.

Evaluation of flaws in accordance with established site procedures using ASME Code and BWRVIP requirements may result in re-inspection or sample expansion.

The Columbia Inservice Inspection (ISI) Program evaluates examination results in accordance with the requirements of Section XI, IWB-3000, Standards for Examination Evaluations. Acceptance of components for continued service is in accordance with the ASME Code or the BWRVIP program guidance, as applicable.

The Columbia program sizes cracks in accordance with the requirements of the ASME Code, Section XI. Additionally, BWRVIP documents, such as BWRVIP-14, BWRVIP-59, and BWRVIP-60, are used for crack growth, where appropriate.

Inspection results are recorded every operating cycle and provided to the NRC after each refueling outage via the Owner's Reports, prepared by the ISI program coordinator.

NUREG-1801 Consistency

The Inservice Inspection (ISI) Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry Experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

Review of recent License Renewal Applications shows that other applicants are using standard ISI inspection techniques and finding and repairing indications prior to any loss of intended function.

Columbia operating experience:

> Recent Columbia operating experience related to inservice inspection is documented in Inservice Inspection Outage Summary Reports. Specific examples of ISI findings are also documented in condition reports. Columbia operating experience is consistent with industry experience; a large number of examinations are being performed, and indications are found and resolved. An occasional repair is being performed prior to loss of intended function. The extensive site-specific operating experience with the ASME Inservice Inspection program provides assurance that the program is effective in managing the effects of aging so that components crediting this program can perform their intended functions consistent with the current licensing basis during the period of extended operation.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program remains effective in managing the identified aging effects.

Conclusion

The Inservice Inspection (ISI) Program manages cracking for components of the reactor coolant pressure boundary, including the reactor vessel, vessel internals, piping, and valves, manages reduction of fracture toughness of cast austenitic stainless steel pump casings and valve bodies, and manages loss of material for components of the vessel internals. The Inservice Inspection (ISI) Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.34 Inservice Inspection (ISI) Program – IWE

Program Description

The Inservice Inspection (ISI) Program – IWE establishes responsibilities and requirements for conducting IWE inspections as required by 10 CFR 50.55a. The ISI Program – IWE includes visual examination of all accessible surface areas of the steel containment and its integral attachments and containment pressure-retaining bolting in accordance with the requirements of the ASME Code, Section XI, 2001 Edition through 2003 Addenda for Subsection IWE.

The in-service examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Code Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

The ISI Program – IWE provides reasonable assurance that the effects of aging are adequately managed to assure that the Primary Containment intended function is performed consistent with the current licensing basis for the period of extended operation.

NUREG-1801 Consistency

The ISI Program – IWE is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S1, "ASME Section XI, Subsection IWE".

The ISI Program – IWE is performed under the Columbia Inservice Inspection (ISI) program. The ISI program is implemented largely to meet the rules and requirements of the ASME Section XI Code. The NUREG-1801 XI.S1 aging management program evaluation has specifically included the Code year (e.g., 2001 edition including the 2002 and 2003 Addenda), as endorsed by the NRC in 10 CFR 50.55a.

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Columbia containment examinations and tests required by the ISI Program – IWE have been implemented in accordance with the established schedule. All the examinations scheduled for the first and second inspection ISI intervals have been completed. All of these examinations and tests performed to date have satisfied the acceptance standards contained within Article IWE-3000, without exception. Currently, there are no containment surfaces or components requiring designation as augmented examination areas. Columbia's Mark II containment is inerted with nitrogen, which provides an atmosphere that is not conducive to corrosion of containment interior surfaces. ISI third interval first period Refueling Outage 18 (R18) also satisfied the acceptance standards contained within Article IWE-3000. Two bolting related defects were found during the IWE inspection and were reported in the R18 ISI summary report, one was related to a bolt for the drywell head and the other for a bolt on the equipment hatch. Both bolt and nut sets were replaced and subsequently pressure tested to confirm pressure boundary integrity of the joint. Inservice inspection records are maintained in accordance with Article IWA 6340 and are maintained in the permanent plant file storage.

The health of the ISI program is reported periodically in terms of performance indicators. The program health reports for 2007 and 2008 indicated no age-related concerns for systems and components within the scope of the ISI Program – IWE. Review of plant operating experience did not reveal containment integrity issues with regards to containment components pertaining to ASME Section XI, Subsection IWE.

The suppression pool wetted surfaces of the submerged areas were examined and found acceptable.

The NRC issued a request for additional information (RAI) on drywell degradation to Columbia in December 1987, since it is the only Mark II plant design with a steel containment and because design features, which contribute to drywell shell corrosion in Mark I containments appear to exist at Columbia. Degradation of the drywell for Mark I containments, due to moisture or water in the sand pockets, is the topic of Generic Letter 87-05. For license renewal, this same topic is the subject of interim staff guidance, with respect to the considerations for aging management during the period of extended operation. Columbia provided a response to the above RAI in February 1988. This response described the pathways through which water could enter the air gap between the steel containment and the shield building, the compressible materials separating the containment and shield wall, and the assessment of the conditions of the containment annulus sand pocket and associated draining system.

Due to the possibility of containment shell degradation from corrosion induced by a moist environment in the sand pocket region, Columbia has committed to monitor humidity levels in this region. Columbia has implemented a procedure to survey the relative humidity of air drawn from within the containment annulus sand pocket region. Review of past inspection results revealed that inspections performed were satisfactory and surveillances since late 1989 indicate no water has been detected; and that there is no evidence of leakage into the sand pocket region. Measurement of sand pocket area humidity provides assurance that water is not accumulating in the sand pocket area, which could cause corrosion of the outer containment shell.

The ISI Program – IWE has been effective in managing the identified aging effects. The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Inservice Inspection (ISI) Program – IWE will be capable of detecting and managing loss of material for the steel surfaces of the containment. The continued implementation of the Inservice Inspection (ISI) Program – IWE provides reasonable assurance that the aging effects will be managed such that the structures and components will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

B.2.35 Inservice Inspection (ISI) Program – IWF

Program Description

The Inservice Inspection (ISI) Program – IWF establishes responsibilities and requirements for conducting IWF inspections as required by 10 CFR 50.55a. The ISI Program – IWF includes visual examination for supports based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1 and those other than piping supports (Class 1, 2, 3, and MC)). The sample size decreases for the less critical supports (ASME Class 2 and 3). Discovery of support deficiencies during regularly scheduled inspections triggers an increase of the inspection scope, in order to ensure that the full extent of deficiencies is identified. The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. IWF specifies acceptance criteria and corrective actions. Supports requiring corrective actions are re-examined during the next inspection period in accordance with the requirements of the ASME Code, Section XI, 2001 Edition through 2003 Addenda for Subsection IWF.

The in-service examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Code Section XI, Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

The ISI Program – IWF provides reasonable assurance that the effects of aging are adequately managed to assure that the Class 1, 2, and 3 component supports intended function is performed consistent with the current licensing basis for the period of extended operation.

NUREG-1801 Consistency

The ISI Program – IWF is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S3, "ASME Section XI, Subsection IWF".

The ISI Program – IWF is performed under the Columbia Inservice Inspection (ISI) program. The ISI program is implemented largely to meet the rules and requirements of the ASME Section XI Code. The NUREG-1801 XI.S3 aging management program evaluation specifically includes the Code year (e.g., 2001 edition including the 2002 and 2003 Addenda), as endorsed by the NRC in 10 CFR 50.55a.

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

The ISI Program – IWF refueling outage 18 (R-18) inspection identified non aging-related degradation such as a spring can setting out of tolerance. This deficiency was further evaluated and accepted in accordance with the ISI program. Another deficiency found was one of the 1/2 inch bolts holding the installed shims in place sheared at a reactor pressure vessel (RPV) stabilizer. An engineering evaluation determined that the condition of the RPV stabilizer is acceptable. A condition report documents the discovery of this sheared bolt. Only one of the two 1/2 inch diameter bolts provided for shim restraint on each side is damaged (i.e., the upper bolt on the right hand side) and the associated shims are not dislodged, the condition does not affect the overall functionality of the RPV stabilizer. The damaged bolt was replaced during refueling outage 19 (R-19).

Examinations were conducted of 100 percent of the locations specified in the program. There were two Code-related successive inspections required to be performed per Subsection IWF during the third interval first inspection period. These inspections, one on a snubber and one on a spring support, were performed during the R-19 outage and the results were acceptable.

The health of the ISI program is reported periodically in terms of performance indicators. The program health reports for 2007 and 2008 indicated no age-related concerns for systems and components within the scope of the ISI Program – IWF. Review of the three previous Refueling Outage (R-18, R-17, and R-16) ISI summary reports and plant operating experience did not reveal age-related issues with regards to ASME Class 1, 2, 3, and MC supports pertaining to ASME Section XI, Subsection IWF.

The ISI Program – IWF has been effective in managing the identified aging effects. The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Inservice Inspection (ISI) Program – IWF will be capable of detecting and managing loss of material and cracking for ASME Class 1, 2, and 3 component supports. The continued implementation of the Inservice Inspection (ISI) Program – IWF provides reasonable assurance that aging effects will be managed such that the structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.36 Lubricating Oil Analysis Program

Program Description

The Lubricating Oil Analysis Program will mitigate the effects of aging for plant components that are within the scope of license renewal and exposed to a lubricating oil environment. The program ensures that the oil environment in the mechanical systems is maintained to the required quality. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to crevice, galvanic, general, or pitting corrosion or selective leaching, or reduction in heat transfer due to fouling, through monitoring of the lubricating oil consistent with manufacturer's recommendations and industry standards. The relevant conditions are specific parameters including particulate and water content, viscosity, neutralization number, and flash point that are indicative of conditions that could lead to age-related degradation of susceptible materials. The Lubricating Oil Analysis Program is a mitigation program.

The Lubricating Oil Analysis Program is supplemented by a one-time inspection of representative areas of lubricating oil systems under the Lubricating Oil Inspection to provide confirmation that loss of material and fouling are effectively mitigated.

NUREG-1801 Consistency

The Lubricating Oil Analysis Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M39, "Lubricating Oil Analysis."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope –**

  Include the following Fire Protection System components that are exposed to lubricating oil within the scope of the program: (1) fire protection diesel engine heat exchangers (lube oil coolers), (2) fire protection diesel engine lube oil piping, and (3) fire protection diesel engine lube oil pump casings.

Operating Experience

The Lubricating Oil Analysis Program is an ongoing program that effectively incorporates the best practices of the industry. Manufacturer recommendations and industry standards are used to establish quality requirements for lubricating oil. The program incorporates the results of operating experience from Columbia and from other utility and industry sources. The program has been, and continues to be, subject to periodic internal and external assessment of the performance to identify strengths and areas for improvement.

Review of Columbia operating experience did not reveal a loss of component intended function for components exposed to lubricating oil that could be attributed to an inadequacy of the Lubricating Oil Analysis Program. Abnormal lubricating oil conditions are promptly identified, evaluated, and corrected. For example, lubricating oil in the feedwater turbine has previously been found contaminated with water. The Lubricating Oil Analysis Program evaluated the condition, determined the source of the water through sampling and analysis, and initiated corrective action. The lubricating oil was replaced and the source of the water leakage was repaired. In addition, levels of lead in emergency diesel generator lube oil have been found that exceeded the specified limits and showed an increasing trend. The evaluation determined the source to be soldered joints on the lube oil coolers. A planned replacement of the oil coolers with a different design was already in place at the time the source was determined, and the coolers have since been replaced.

Conclusion

The Lubricating Oil Analysis Program will manage loss of material and reduction in heat transfer for susceptible components in lubricating oil, through monitoring of the relevant parameters. The Lubricating Oil Analysis Program, with the required enhancements, and supplemented by the Lubricating Oil Inspection prior to entering the period of extended operation provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.37 Lubricating Oil Inspection

Program Description

The Lubricating Oil Inspection is a new one-time inspection that will detect and characterize the condition of materials in systems and components for which the Lubricating Oil Analysis Program (a mitigation program) is credited with aging management. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to crevice, galvanic, general, or pitting corrosion or selective leaching, or reduction in heat transfer due to fouling, has occurred on surfaces exposed to lubricating oil.

Implementation of the Lubricating Oil Inspection will provide additional confirmation of Lubricating Oil Analysis Program effectiveness and further assurance that the intended functions of susceptible components will be maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Lubricating Oil Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI. M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Lubricating Oil Inspection includes the oil-wetted surfaces of aluminum, aluminum alloy, copper alloy, copper alloy > 15% Zn, steel, gray cast iron, and stainless steel components in the following license renewal systems:
  - Control Rod Drive (CRD) System
  - Control Room Chilled Water (CCH) System
  - Diesel Cooling Water (DCW) System
  - Diesel Engine Starting Air (DSA) System
  - Diesel Exhaust (DE) System
  - Diesel Generators (DG) System

- Diesel Lubricating Oil (DLO) System
- Fire Protection (FP) System
- Low Pressure Core Spray (LPCS) System
- Reactor Core Isolation Cooling (RCIC) System
- Standby Service Water (SW) System

A representative sample of components, with special emphasis on locations that may be susceptible to the collection of entrained water, will be examined for evidence of loss of material (due to crevice, galvanic, general, or pitting corrosion or selective leaching) or reduction in heat transfer due to fouling, or to confirm a lack thereof, and the results applied to all of the systems and components within the scope of the inspection, based on engineering evaluation.

- Preventive Actions
  No actions are taken as part of the Lubricating Oil Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Lubricating Oil Inspection include wall thickness and visual evidence of internal or external surface degradation as measures of a loss of material or fouling. Inspections will be performed by qualified personnel using established NDE techniques.

- Detection of Aging Effects
  The Lubricating Oil Inspection will use a combination of established volumetric and visual examination techniques and nondestructive methods performed by qualified personnel on a sample population of subject components to identify evidence of loss of material or fouling or to confirm a lack thereof.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will focus on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Lubricating Oil Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  No actions are taken as part of the Lubricating Oil Inspection to monitor or trend inspection results. This is a one-time inspection activity used to determine if, and to what extent, further actions, including monitoring and trending, may be required.

Sample size will be determined by engineering evaluation, as described for the *Parameters Monitored or Inspected* element above. Results of inspection activities that require further evaluation and resolution (e.g., if degradation is detected), if any, will be evaluated using the Columbia corrective action process, including expansion of the sample size and inspection locations to determine the extent of the degradation.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Lubricating Oil Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effects. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging mechanism is slow acting. Inspection methods are to be consistent with accepted industry practices.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has identified no instances of age-related degradation in lubricating oil environments. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that a one-time inspection activity remains the appropriate method for managing the effects of aging for systems within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Lubricating Oil Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.38 Masonry Wall Inspection

Program Description

The Masonry Wall Inspection is an existing condition monitoring program consisting of inspection activities to detect aging and age-related degradation for masonry walls identified as performing intended functions in accordance with 10 CFR 54.4.. Masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program.

The Masonry Wall Inspection is implemented as part of the Structures Monitoring Program conducted for the Maintenance Rule.

Aging effects identified within the scope of the Masonry Wall Inspection are detected by visual inspection of external surfaces prior to the loss of the structure's or component's intended functions. Masonry walls are visually examined at a frequency selected to ensure there is no loss of intended function between inspections and that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

NUREG-1801 Consistency

The Masonry Wall Inspection is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S5, "Masonry Wall Program."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program elements:

- **Parameters Monitored or Inspected, Acceptance Criteria –**

  Specify that for each masonry wall, the extent of observed masonry cracking or degradation of steel edge supports and bracing are evaluated to ensure that the current evaluation basis is still valid. Corrective action is required if the extent of masonry cracking or steel degradation is sufficient to invalidate the evaluation basis. An option is to develop a new evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation).

Operating Experience

The Masonry Wall Inspection includes all masonry walls identified in accordance with 10 CFR 54.4. This includes masonry walls in the Circulating Water Pump House, Turbine Generator Building, and the NSR portion of the Radwaste Control Building. There are no safety-related masonry walls at Columbia. Some removable shielding block walls are installed between steel plates in the proximity of Class 1 piping in the Reactor Building. These shield walls have been evaluated to assure that they could withstand a combination dead load plus seismic load resulting from a safe shutdown earthquake.

The Masonry Wall Inspection has been effective in managing the identified aging effects. Visual examinations conducted by the Masonry Wall Inspection, as implemented by the Structures Monitoring Program, have not found any age-related problems or degraded conditions for masonry walls that could affect their intended function.

Therefore the Masonry Wall Inspection, as implemented by the Structures Monitoring Program, has provided reasonable assurance that aging effects are being managed.

The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Masonry Wall Inspection with enhancement, as part of the Structures Monitoring Program, will be capable of detecting and managing aging effects for the masonry walls within the scope of license renewal. The continued implementation of the Masonry Wall Inspection, with the required enhancement, provides reasonable assurance that the effects of aging will be managed so that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.39 Material Handling System Inspection Program

Program Description

The Material Handling System Inspection Program is credited with managing loss of material for cranes (including bridge, trolley, rails, and girders), monorails, and hoists within the scope of license renewal. The Material Handling System Inspection Program is based on guidance contained in ANSI B30.2 for overhead and gantry cranes, ANSI B30.11 for monorail systems and underhung cranes, and ANSI B30.16 for overhead hoists. The inspections monitor structural members for signs of corrosion and wear. The inspections are performed periodically for installed cranes and hoists (e.g., annually for the reactor building crane, other NUREG-0612 heavy load handling systems and the refueling platform).

The Material Handling System Inspection Program provides reasonable assurance that the effects of aging are adequately managed for Columbia cranes (including bridge, trolley, rails, and girders), monorails, and hoists and that their intended function will continue to be performed consistent with the current licensing basis for the period of extended operation.

NUREG-1801 Consistency

The Material Handling System Inspection Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancement listed below will be implemented in the identified program element:

- **Detection of Aging Effects –**

  Ensure jib cranes and electrically operated hoists are visually inspected for corrosion.

Operating Experience

A review of crane and hoist inspections previously conducted at Columbia and of industry operating experience confirms the acceptability of the inspections and their frequency in that degradation of cranes (including bridge, trolley, rails, and girders), monorails, and hoists was detected prior to loss of function. Related crane and hoist inspections have found no age-related degradation problems.

The health of the Material Handling System Inspection Program is reported periodically in terms of performance indicators. The program health reports for 2007 and 2008 noted no age-related improvements for the program.

The Material Handling System Inspection Program has been effective in managing the identified aging effects. The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Material Handling System Inspection Program will be capable of detecting and managing loss of material for cranes (including bridge, trolley, rails, and girders), monorails, and hoists within the scope of license renewal. The continued implementation of the Material Handling System Inspection Program, with the required enhancement, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.40 Metal-Enclosed Bus Program

Program Description

The Metal-Enclosed Bus Program will manage the aging of metal-enclosed bus within the scope of license renewal. The program provides for the periodic visual inspection of metal-enclosed bus, along with the use of thermography, in order to determine if age-related degradation is occurring. The program will provide reasonable assurance that the electrical components will perform their intended functions for the period of extended operation.

The Metal-Enclosed Bus Program is a new aging management program that will be implemented prior to the period of extended operation, with the first inspection to be completed prior to the end of the current operating license, and with both the thermography portion and the visual inspection portion to be performed every 10 years thereafter.

The metal-enclosed bus addressed by this program includes the non-segregated bus associated with transformer E-TR-S (the 230-kV startup auxiliary power transformer).

NUREG-1801 Consistency

The Metal-Enclosed Bus Program is a new Columbia program that will be consistent with the 10 elements of an effective aging management program, as described in NUREG-1801, Section XI.E4, "Metal-Enclosed Bus," with an exception.

Exceptions to NUREG-1801

<u>Program Elements Affected:</u>

- **Parameters Monitored or Inspected**

  The Metal-Enclosed Bus Program will perform the inspection of the various bus joints, seals, and gaskets when the bus assembly covers are removed for inspection of the internal components, rather than the Structures Monitoring Program (as listed in NUREG-1801 item VI.A-12). The Structures Monitoring Program will perform the inspection of the bus assembly external surfaces and the bus assembly structural supports.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program

The Metal-Enclosed Bus Program is credited with detecting aging effects for in-scope metal-enclosed bus. The in-scope bus is limited to non-segregated metal-enclosed bus in the 6.9-kV and 4.16-kV electrical systems associated with the off-site power supply (via transformer E-TR-S).

- Preventive Actions
  The Metal-Enclosed Bus Program is an inspection program; no actions are taken to prevent or mitigate aging degradation.

- Parameters Monitored or Inspected
  The Metal-Enclosed Bus Program will inspect bus insulation for anomalies, such as embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus enclosure will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The internal bus supports (i.e., internal to the enclosure) will be inspected for structural integrity and any sign of cracks.

  The Metal-Enclosed Bus Program will inspect a sample of bus bolted connections via thermography for signs of loose connections. The in-scope bus will be checked from the exterior with the bus energized to provide gross detection of circuit hot spots.

  The Metal-Enclosed Bus Program will inspect the bus joints, seals, and gaskets when the assembly covers are removed for inspection of the internal components.

- Detection of Aging Effects
  The Metal-Enclosed Bus Program will utilize thermography to check the bolted connections in the non-segregated metal-enclosed bus that is within the license renewal scope. The thermography inspection will be performed for representative portions of the in-scope non-segregated metal-enclosed bus.

  The Metal-Enclosed Bus Program also includes visual inspection of the internal bus enclosure, bus insulation, and internal bus supports. The bus enclosure will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation will be inspected for anomalies, such as signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports (internal to the enclosure) will be inspected for structural integrity and signs of cracking. The elastomers used to seal the bus enclosure assembly will be inspected for embrittlement, cracking, loosening, flaking, peeling, and other indications of aging degradation.

  Both the thermography inspection and the visual inspections will be performed at least once every 10 years, with the first inspections to be completed within the 10-year period prior to the end of the current operating license.

The external surfaces of the bus assemblies and the external bus enclosure supports (the structural supports for the entire bus assembly) will be inspected under the Structures Monitoring Program.

- Monitoring and Trending
  The Metal-Enclosed Bus Program will not include trending actions. If anomalies are found during the inspection process, they will be addressed at that time through the corrective action program.

- Acceptance Criteria
  The acceptance criteria for the thermography portion of the Metal-Enclosed Bus Program will be based on acceptance criteria already used in the thermography process at Columbia. The acceptance criteria for the visual inspection portion (of the bus enclosure) will be that the metal-enclosed bus conductor insulation is free from unacceptable visual indications of surface anomalies, such as embrittlement, cracking, melting, swelling, and discoloration, and that the metal-enclosed bus is also free from unacceptable indications of corrosion, cracking, foreign debris, excessive dust buildup, or evidence of moisture intrusion. In addition, the elastomers used to seal adjacent bus enclosures (exterior) are to be free from indications of aging degradation, such as embrittlement, cracking, loosening, flaking, and peeling. The seal cover gaskets will be inspected when the bus assembly covers are removed for inspection of the internal components. The seal cover gaskets (elastomers) are to be free from indications of aging degradation, such as embrittlement, cracking, loosening, flaking, and peeling.

  The external surfaces of the bus assemblies and the external bus enclosure supports (the structural supports for the entire bus assembly) will be inspected under the Structures Monitoring Program.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

  In addition, for the Metal-Enclosed Bus Program, further investigation and evaluation are performed when the acceptance criteria are not met. Corrective actions may include (but are not limited to) cleaning, drying, an increased inspection frequency, replacement, or repair of the affected metal-enclosed bus components. If an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible metal-enclosed bus.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Metal-Enclosed Bus Program is a new program for which there is no direct site-specific operating experience. Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

  Plant operating experience has shown that the corrective action program has addressed issues related to bus and bus enclosure degradation in recent years. For example, corrosion was identified on insulators used to support bus associated with the unit normal auxiliary transformer (which is not in scope for license renewal). In addition, the corrective action program noted that the use of thermography would provide an improvement to the bus preventive maintenance program. Industry operating experience will be included in the development of this program.

Required Enhancements

Not applicable, this is a new program.

Conclusion

The Metal-Enclosed Bus Program will manage aging degradation for metal-enclosed bus. The Metal-Enclosed Bus Program will provide reasonable assurance that the aging effects will be managed such that metal-enclosed bus subject to aging management review will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

B.2.41 Monitoring and Collection Systems Inspection

Program Description

The Monitoring and Collection Systems Inspection is a new one-time inspection that will detect and characterize the conditions on the internal surfaces of subject mechanical components that are exposed to equipment and area drainage water and other potential contaminants and fluids. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to crevice, galvanic, general, or pitting corrosion, erosion, or MIC has occurred. The inspection also provides direct evidence as to whether, and to what extent, cracking due to SCC of susceptible materials in susceptible locations has occurred.

Implementation of the Monitoring and Collection Systems Inspection will provide assurance (and confirmation) that the pressure boundary of susceptible safety-related components is maintained consistent with the current licensing basis during the period of extended operation. Implementation of the inspection will also provide assurance (and confirmation) that the structural integrity of susceptible NSR components will be maintained such that spatial interactions (e.g., leakage) will not result in the loss of any safety-related component intended functions during the period of extended operation.

NUREG-1801 Consistency

The Monitoring and Collection Systems Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The scope of the Monitoring and Collection Systems Inspection includes the internal surfaces of subject mechanical components in the following plant drainage and collection systems that are exposed to potentially radioactive drainage water (untreated water), and in systems with other potential contaminants and fluids during normal plant operations:

  - Equipment Drains Radioactive (EDR) System
  - Floor Drains (FD) System

- Floor Drains Radioactive (FDR) System
- Fuel Pool Cooling (FPC) System
- Miscellaneous Waste Radioactive (MWR) System
- Plant Sanitary Drains (PSD) System
- Process Sampling Radioactive (PSR) System
- Reactor Closed Cooling (RCC) Water System

A representative sample of components in these systems, to be defined in the implementing documents, and to include containment isolation piping and valve bodies, will be examined for evidence of a loss of material (due to crevice, galvanic, general, or pitting corrosion, erosion, or MIC), or to confirm a lack thereof, and the results applied to all of the systems and components within the scope of the inspection, based on engineering evaluation. In addition, the representative sample will include stainless steel components exposed to temperatures greater than 140 °F that will be examined for evidence of cracking due to SCC.

- Preventive Actions
  No actions are taken as part of the Monitoring and Collection Systems Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Monitoring and Collection Systems Inspection include wall thickness or visual evidence of internal surface degradation, as measures of a loss of material or cracking in susceptible materials. Inspections will be performed by qualified personnel using established NDE techniques.

- Detection of Aging Effects
  The Monitoring and Collection Systems Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on a sample population of subject components to identify evidence of loss of material or cracking in susceptible materials or to confirm a lack thereof on the susceptible internal surfaces of the components.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and the lowest design margins. The sample population will include at least one location for containment isolation components.

The Monitoring and Collection Systems Inspection activities will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and location if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using the Columbia corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
The Monitoring and Collections Systems Inspection is a new one-time inspection activity for which plant operating experience has not shown the need to manage the aforementioned aging effects for the in-scope systems. The inspection provides for confirmation of material conditions near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

A review of Columbia operating experience to date identified an occurrence of loss of material due to corrosion within the FDR System in 2003. The susceptible FDR piping and valves were subsequently re-designed to eliminate standing water and replaced with a corrosion resistant, stainless steel, material in 2005. No additional instances of corrosion have occurred in the FDR System since the implementation of the modification.

The site corrective action program, and an ongoing review of industry operating experience, will be used to ensure that the identified aging effects do not require management for the systems within the scope of this activity.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Monitoring and Collection Systems Inspection will verify that there are no aging effects requiring management for the subject components, or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation, and that spatial interactions (e.g., leakage) will not result in loss of safety-related component intended functions during the period of extended operation.

B.2.42 Open-Cycle Cooling Water Program

Program Description

The Open-Cycle Cooling Water Program manages loss of material due to crevice, galvanic, general, pitting, and MIC, and erosion for components located in the Standby Service Water and Plant Service Water systems, and components connected to or serviced by those systems, and in the Tower Makeup Water and Circulating Water systems. The program also manages fouling due to particulates (e.g., corrosion products) and biological material (micro- and macro-organisms) resulting in reduction in heat transfer for heat exchangers within the scope of the program. In addition, the program manages cracking for copper alloy > 15% Zn components in the Process Sampling System and for aluminum components in the HVAC systems that are subject to condensation.

The Open-Cycle Cooling Water Program consists of inspections, surveillances, and testing to detect the presence, and assess the extent, of fouling, loss of material, and cracking, combined with chemical treatments and cleaning activities to minimize fouling, loss of material, and cracking. The existing program is a combination condition monitoring and mitigation program that implements the recommendations of NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

NUREG-1801 Consistency

The Open-Cycle Cooling Water Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801 Section XI.M20, "Open-Cycle Cooling Water System," with exceptions.

Exceptions to NUREG-1801

<u>Program Elements Affected:</u>

- **Preventive Actions –**

  NUREG-1801 states that system components are lined or coated to protect underlying metal surfaces from being exposed to aggressive cooling water environments. Protective coatings on the inner walls are not used in the service water systems that are within the scope of license renewal at Columbia.

- **Monitoring and Trending –**

  NUREG-1801 states that testing and inspections are performed annually and during refueling outages. Inspection frequencies for the Open-Cycle Cooling Water Program are based on operating conditions and past history; flow rates, water quality, lay-up, and heat exchanger design.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope –**

  Address loss of material due to cavitation erosion (for the Standby Service Water (SW), Circulating Water (CW), Plant Service Water (TSW), and Tower Make-Up (TMU) systems) with activities such as opportunistic inspections of portions of the systems that have had indications of cavitation erosion in the past.

- **Scope –**

  Include the NSR components within the license renewal scope in the SW, CW, TSW, and TMU systems, and the NSR components served by or connected to the TSW System that are in the following plant systems:

  - Process Sampling (PS) System
  - Process Sampling Radioactive (PSR) System
  - Radwaste Building Mixed Air (WMA) System
  - Radwaste Building Return Air (WRA) System
  - Reactor Building Return Air (RRA) System
  - Reactor Closed Cooling Water (RRC) System

Operating Experience

The Open-Cycle Cooling Water Program is an ongoing program that has implemented the recommended actions of NRC GL 89-13 and has justified any alternatives to those recommendations. The health of the program and corresponding systems are periodically reported, including chemistry trends and material conditions. Industry operating experience is evaluated for impact to Columbia, and periodic self assessments are conducted. As a result, Columbia has programs in place with operating experience to demonstrate that the effects of aging on the service water systems, and on the safety-related heat exchangers that they serve, as well as on the plant service water systems and NSR heat exchangers they serve, will be effectively managed during the period of extended operation.

In addition, annual ultimate heat sink and spray pond performance, as well as related GL 89-13 systems, components, and controls, is a subject of NRC integrated inspection. In recent years, reviews were performed by NRC inspectors to verify the acceptability of test methods and conditions, acceptance criteria, use of instrument uncertainties, frequency of testing, biofouling controls, compliance with design parameters, and the extrapolation of test data to design conditions. No findings of significance with respect to the effectiveness of the existing program were identified during these integrated inspections.

Furthermore, a review of plant-specific operating experience has identified several instances of damage due to erosion, designated as cavitation erosion. There have been repeated instances of leaks and failures in the SW System, which were cavitation-related. The design and operational adjustments have not fully precluded subsequent cavitation-related failures. That is, design and operational adjustments have corrected the issues sufficient to support continued operation of the plant, but have not fully eliminated the occurrence of cavitation erosion in the service water or attached systems. Therefore, in the course of normal operation during the period of extended operation, it is plausible that cavitation erosion could have the same effect as other forms of erosion (e.g., particulate) in the raw water environment of the service water and attached systems.

Conclusion

The Open-Cycle Cooling Water Program will detect and manage loss of material and reduction in heat transfer for susceptible components in raw water environments. The Open-Cycle Cooling Water Program, with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.43 Potable Water Monitoring Program

Program Description

The Potable Water Monitoring Program mitigates damage due to loss of material due to corrosion and erosion for components that contain potable water and are within the scope of license renewal to ensure that the integrity of piping and components is maintained. The Potable Water Monitoring Program is an existing mitigation program that is comprised of water treatment activities, including flocculation, sedimentation, filtration, and chemical addition.

Prior to the period of extended operation, the Potable Water Monitoring Program will be enhanced to include periodic inspection activities to provide additional confirmation that the integrity of piping and components will be maintained for the period of extended operation. As such, the Potable Water Monitoring Program will be a combination mitigation and condition monitoring program. At least one inspection will be conducted within the 10-year period prior to the period of extended operation.

NUREG-1801 Consistency

The Potable Water Monitoring Program is an existing Columbia program, with required enhancements, that is plant-specific. There is no corresponding aging management program described in NUREG-1801.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Potable Water Monitoring Program is credited for managing loss of material for aluminum, copper alloy, copper alloy > 15% Zn, gray cast iron, and steel components that are exposed to potable water in the following systems:
  - Reactor Building Outside Air (ROA) System
  - Potable Cold Water (PWC) System
  - Potable Hot Water (PWH) System
- Preventive Actions
  The Potable Water Monitoring Program is an existing mitigation program comprised of water treatment activities, including flocculation, sedimentation, filtration, and chemical addition.

- Parameters Monitored or Inspected
  The Potable Water Monitoring Program monitors the water treatment plant performance and the overall status of the potable water system, including water quality.

- Detection of Aging Effects
  The Potable Water Monitoring Program will be enhanced to use a combination of established volumetric and visual examination techniques performed by qualified personnel on locations within the PWC, PWH, and ROA systems, as determined by engineering evaluation, to identify evidence of a loss of material, or to confirm a lack thereof. At least one inspection will be conducted within the 10-year period prior to the period of extended operation.

  Based on operating experience, it is necessary that inspections be conducted at least once every five years, and include components of the PWC and PWH systems that are located in the Reactor Building, and components associated with the ROA air washer (ROA-AW-1), including the air washer housing.

- Monitoring and Trending
  The Potable Water Monitoring Program monitors the water treatment plant performance and the overall status of the potable water system, including water quality, and the results are recorded and trended.

- Acceptance Criteria
  The acceptance criteria for potable water system inspections are: indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

  Acceptance criteria have been established for potable water quality, which minimizes the presence of impurities that could cause degradation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  As revealed by the operating experience review, corrosion and subsequent system leakage has been a recurring problem in the Columbia potable water systems. These problems have been detected, and components have been isolated and repaired or replaced in a timely manner, in accordance with the corrective action program. None of the system leakage problems have occurred in portions of the systems that are within the Reactor Building where they could affect safety-related equipment due to leakage or spray. The majority of the leaks have been in the yard loop piping which is external to the power block structures and is buried. This piping is PVC material which makes it susceptible to leaks due to changes in temperature related to location and environment. The piping in the Reactor Building is not exposed to the same environment (i.e., indoor air not soil) and is not of the same material (i.e., is metallic not PVC).

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Detection of Aging Effects –**

  Include periodic inspection activities. Based on operating experience, it is necessary that inspections be conducted at least once every five years, and include components of the PWC and PWH systems that are located in the Reactor Building, and components associated with the ROA air washer (ROA-AW-1), including the air washer housing.

Conclusion

The Potable Water Monitoring Program, supplemented by at least one inspection prior to entering the period of extended operation, and with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.44 Preventive Maintenance – RCIC Turbine Casing

Program Description

The Preventive Maintenance – RCIC Turbine Casing manages loss of material due to general corrosion on the internal surfaces of the Reactor Core Isolation Cooling (RCIC) pump turbine casing and associated piping and piping components downstream from the steam admission valve. Preventive Maintenance – RCIC Turbine Casing is a condition monitoring activity comprised of periodic inspection and surveillance activities to detect aging and age-related degradation.

NUREG-1801 Consistency

Preventive Maintenance – RCIC Turbine Casing is an existing Columbia program that is plant-specific. There is no corresponding aging management program described in NUREG-1801.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  Preventive Maintenance – RCIC Turbine Casing is credited for managing loss of material due to general corrosion on the internal steel surfaces in the RCIC pump turbine casing and the in-scope piping and piping components in steam lines downstream from the steam admission valve. These components are exposed to steam during RCIC system operation and testing and to an ambient air internal environment during normal plant operation. The ambient (untreated, moist) air internal environment is a result of steam having either condensed and drained to the barometric condenser or vented to the suppression chamber (drywell). Inspections are focused on the casing with the results applying to the other associated components because of the similarities in materials and environment. For example, if inspection results indicate an absence of general corrosion on the turbine casing, then general corrosion would not be expected on any of the other susceptible components.

- Preventive Actions
  Preventive Maintenance – RCIC Turbine Casing does not include any actions to prevent or mitigate the effects of aging.

- Parameters Monitored or Inspected
  Preventive Maintenance – RCIC Turbine Casing inspects the internal steel surfaces of the RCIC pump turbine casing for signs of degradation (leakage, pitting, corrosion, etc.) that might be indicative of loss of material.

- Detection of Aging Effects
  In accordance with the information provided in the *Monitoring and Trending* element, Preventive Maintenance – RCIC Turbine Casing detects loss of material prior to any loss of component intended function.

- Monitoring and Trending
  Preventive Maintenance – RCIC Turbine Casing is a condition monitoring activity that is performed by qualified individuals at established intervals to identify internal degradation of the turbine casing through visual inspection. If unacceptable deterioration is noted during the internal inspection of the turbine casing, the inspection results will be evaluated through the corrective action program.

- Acceptance Criteria
  The acceptance criteria for Preventive Maintenance – RCIC Turbine Casing are no unacceptable visual indications of loss of material. Unacceptable indications are those that are determined by engineering evaluation to degrade the components to such an extent that they may not be capable of performing their intended function (pressure boundary integrity) until the next scheduled inspection.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The elements that comprise Preventive Maintenance – RCIC Turbine Casing are consistent with industry practice and have proven effective in maintaining the material condition of the RCIC pump turbine, including the casings.

  A review of the most recent work order documentation for the turbine internal inspections reveals that RCIC turbine casing inspections are performed in accordance with procedure, results are documented and retrievable, and that, if degradation is indicated, corrective actions are taken. A review of the most recent plant-specific operating experience, through a search of condition reports, revealed that no loss of pressure boundary integrity has occurred that was, or could have been, attributed to the aging effects that are in the scope of the program. Some minor leakage was identified that was corrected and the material condition was monitored, as indicated in the system health reports for 2007, to ensure that no further degradation or loss of function occurred. Other issues in the system health reports for 2008 involve valve seat and packing leakage, which are issues that are not within the scope of license renewal.

Required Enhancements

None.

Conclusion

Preventive Maintenance – RCIC Turbine Casing will detect and manage loss of material. The continued implementation of Preventive Maintenance – RCIC Turbine Casing provides reasonable assurance that the effects of aging will be managed such that components subject to aging management will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.45 Reactor Head Closure Studs Program

Program Description

The Reactor Head Closure Studs Program manages cracking due to SCC and loss of material due to corrosion for the reactor head closure stud assemblies (studs, nuts, washers, and bushings.)

The Reactor Head Closure Studs Program examines reactor vessel stud assemblies in accordance with the examination and inspection requirements specified in Table IWB-2500-1. The program includes visual and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. Inspections include VT-1 visual examination of the nuts, washers, and bushing and volumetric examination of studs and threads. VT-2 inspections for leak detection are performed during system pressure tests. The inspection of the reactor vessel closure studs, performed in accordance with ASME Code, Section XI, Subsection IWB, Table IWB 2500-1 (2003 addenda), includes volumetric examinations rather than the surface examinations called out in paragraph NB-2545 or NB-2546 of Section III of the ASME Code.

The ultimate tensile stress for the Columbia studs and nuts (SA-540 Grade B23 or B24) is less than the 170 ksi limitation in Regulatory Guide 1.65 and are therefore bounded by the NUREG-1801 program. There are no metal platings applied to the Columbia closure studs, nuts, or washers. A phosphate coating is applied to threaded areas of studs and nuts and bearing areas of nuts and washers to act as a rust inhibitor and to assist in retaining lubricant on these surfaces.

The Reactor Head Closure Studs Program includes the preventive measures of RG 1.65 to mitigate cracking, including the use of a stable lubricant.

The Reactor Head Closure Studs Program credits portions of the Inservice Inspection (ISI) Program.

NUREG-1801 Consistency

The Reactor Head Closure Studs Program is an existing Columbia program that is consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M3, "Reactor Head Closure Studs."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

Industry operating experience:

NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

Stress corrosion cracking has occurred in other BWR reactor head closure studs as described in a GE service information letter.

The Reactor Head Closure Studs Program detects aging effects using nondestructive examination (NDE) visual, surface and volumetric techniques to detect and characterize flaws. These techniques are widely used and have been demonstrated effective at detecting aging effects during inspections performed to meet ASME Section XI Code requirements. A review of operating experience in recently submitted License Renewal Applications includes the following.

- Surface examination of RPV studs and nuts in 2001 at Cooper Nuclear Station during RE20 identified a recordable indication for RPV nuts, two non-recordable indications for RPV studs and a non-recordable for RPV washers. The recordable indication was evaluated as satisfactory.
- Duane Arnold Energy Center has had no recordable indications reported for the RPV stud and nut inspections as required by the ASME Section XI.
- Crystal River reports no cracking or loss of material for the Unit 3 Closure Head Stud Assembly. There have been no aging effects identified that have been attributed to wear, loss of material or stress-corrosion cracking.
- Palo Verde reported no cracking due to SCC or IGSCC for PVNGS reactor vessel studs, nuts, flange stud holes, or washers.

Industry operating experience will be considered when implementing this program. Plant operating experience for this program will be gained as it is implemented during the period of extended operations, and will be factored into the program. As such, operating experience assures that implementation of the Reactor Head Closure Studs Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Columbia operating experience:

> Review of Columbia operating experience (condition reports, work orders, etc.) has not revealed any reactor head closure stud cracking or loss of material. The existing program is adequately managing the aging of the reactor head closure studs to maintain the intended function, and will continue to do so for the period of extended operation.

The Reactor Head Closure Studs Program has been developed based on relevant plant and industry operating experience. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the new program is effective in managing the identified aging effects.

Conclusion

The Reactor Head Closure Studs Program manages cracking and loss of material for the reactor head closure stud assemblies. The Reactor Head Closure Studs Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.46 Reactor Vessel Surveillance Program

Program Description

The Reactor Vessel Surveillance Program manages the reduction of fracture toughness due to radiation embrittlement for the low alloy steel reactor vessel shell and welds in the beltline region. The Reactor Vessel Surveillance Program is a condition monitoring program developed in response to 10 CFR 50 Appendix H.

The Columbia program is part of the BWRVIP Integrated Surveillance Program (ISP) that includes multiple BWR vessels. The BWRVIP ISP is an NRC-approved program that appropriately implements the requirements of Appendix H to 10 CFR Part 50. Testing and reporting done by the BWRVIP ISP is performed in accordance with the requirements of ASTM E 185 (1982). The NRC has approved the use of the BWRVIP ISP in place of a unique plant program for Columbia. The BWRVIP ISP has been revised for License Renewal, as documented in BWRVIP-116, to ensure representative capsules are irradiated to fluence levels corresponding to the end of the period of extended operation.

The BWRVIP ISP uses material surveillance capsules in BWR plants, as well as supplemental capsules irradiated in host plants, to provide data which bounds all operating BWR plants. No surveillance capsules from Columbia are included in the BWRVIP ISP; however, the Columbia surveillance capsules will continue to be maintained in the reactor vessel in standby (deferred) status as required by the ISP. Capsules from host plants will be removed and tested in accordance with the ISP implementation plan defined in BWRVIP-86-A. Results from these tests that are applicable to Columbia will provide the necessary data to monitor embrittlement for the Columbia reactor pressure vessel (RPV). EN will apply the results of the ISP capsule testing to Columbia.

The neutron fluence values used for the projections of neutron embrittlement effects are determined using NRC-approved methodology. The exposure conditions of the reactor vessel are monitored to ensure that they continue to be consistent with those used to project the effects of embrittlement to the end of the license term. If the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection to 60 years is reviewed; and, if deemed appropriate, a revised fluence projection is prepared and the effects of the revised fluence analysis on neutron embrittlement calculations will be evaluated.

The determination of neutron embrittlement effects for Columbia fully complies with NRC Regulatory Guide 1.99, Revision 2. Projections for neutron embrittlement effects have been adjusted to account for the specific nickel and copper contents of the Columbia materials. The extent of reactor vessel embrittlement for upper-shelf energy (USE) and adjusted reference temperature for nil-ductility transition (ART) is projected for 60 years in accordance with Regulatory Guide 1.99, Revision 2. These projections will be updated throughout the remaining life of Columbia if new information (e.g., material data from the ISP applicable to Columbia, or revised fluence values) becomes available. P-T limits will be managed for the period of extended operation. Participation in the BWRVIP ISP will ensure that changes to irradiation embrittlement information will be factored into the determination of any required operating restrictions in a timely fashion.

The Columbia program requires that untested capsules either be returned to the reactor vessel or maintained in storage for possible future re-insertion. As no Columbia capsules are scheduled for testing, the disposition of tested capsules is not applicable to Columbia.

The Columbia Reactor Vessel Surveillance Program will also monitor the Effective Full Power Years (EFPY) accumulated by the unit and ensure that the P-T limit curves contained in plant technical specifications are updated periodically such that they are always valid beyond the EFPY that the plant has accumulated. Reactor vessel P-T limits will thus be managed as a TLAA for the period of extended operation.

NUREG-1801 Consistency

The Reactor Vessel Surveillance Program is an existing Columbia program that is consistent with the 10 elements of an effective integrated surveillance program as described in NUREG-1801, Section XI.M31, "Reactor Vessel Surveillance."

Exceptions to NUREG-1801

None.

Required Enhancements

None.

Operating Experience

The Reactor Vessel Surveillance Program has been effective in managing reduction of fracture toughness for the reactor vessel beltline components.

Industry operating experience:

Columbia participates in the BWRVIP ISP as described in reports BWRVIP-86-A and BWRVIP-116. Participation in the ISP ensures that future operating experience from all participating BWRs will be factored into the Reactor Vessel Surveillance Program. The NRC has concurred that the Reactor Vessel Surveillance Program is an acceptable program based on the NRC safety evaluation reports (SERs) for the

BWRVIP ISP and the SER for the replacement of the Columbia site-specific program with the ISP.

Columbia operating experience:

A review of Columbia operating experience identified no issues related to reactor vessel embrittlement. Surveillance specimen analysis and embrittlement projections are being performed by the BWRVIP ISP.

The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the new program is effective in managing the identified aging effects.

Conclusion

The Reactor Vessel Surveillance Program manages reduction of fracture toughness for components of the reactor vessel beltline region. The Reactor Vessel Surveillance Program provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.47 Selective Leaching Inspection

Program Description

The Selective Leaching Inspection will detect and characterize the conditions on internal and external surfaces of subject components that are exposed to raw water, treated water (including closed cycle cooling water and steam), fuel oil, soil (buried), and moist air (including condensation) environments. This one-time inspection provides direct evidence through a combination of visual examination and material hardness testing, or NRC approved alternative, of whether, and to what extent, a loss of material due to selective leaching has occurred or is likely to occur that could result in a loss of intended function.

Implementation of the Selective Leaching Inspection prior to the period of extended operation will ensure that the pressure boundary integrity of susceptible components is maintained consistent with the current licensing basis during the period of extended operation. Implementation of the inspection will also provide added assurance that the structural integrity of susceptible components is maintained such that spatial interaction will not impair or prevent a safety-related intended function during the period of extended operation.

NUREG-1801 Consistency

The Selective Leaching Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M33, "Selective Leaching of Materials."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Selective Leaching Inspection is credited for evaluating the condition of selective leaching susceptible components and assessing their ability to perform their intended function during the period of extended operation. Susceptible components include piping and tubing, valve bodies, pump casings, filter bodies, heat exchanger components, hydrants, strainers, tanks, and trap bodies. Components within the scope of the program are formed of gray cast iron or copper alloy > 15% Zn. The components are exposed to raw water, treated water (including closed cycle cooling water and steam), fuel oil, soil (buried), or moist air (including condensation) environments during normal plant operations. The one-time

inspection includes a visual examination and hardness measurement, or NRC approved alternative, of a sample set of components to determine whether selective leaching is occurring or is likely to occur in the period of extended operation.

The aging management activity is credited for the following systems:

- Auxiliary Steam (AS) System
- Circulating Water (CW) System
- Containment Nitrogen (CN) System
- Control Rod Drive (CRD) System
- Diesel Building HVAC Systems (DMA)
- Diesel Fuel Oil (DO) System
- Fire Protection (FP) System
- High Pressure Core Spray (HPCS) System
- Low Pressure Core Spray (LPCS) System
- Main Steam (MS) System
- Plant Service Water (TSW) System
- Potable Cold Water (PWC) System
- Potable Hot Water (PWH) System
- Process Sampling (PS) System
- Radwaste Building Chilled Water (WCH) System
- Radwaste Building HVAC Systems (WEA, WMA, WOA, WRA)
- Reactor Building HVAC Systems (REA, ROA, RRA)
- Residual Heat Removal (RHR) System
- Standby Service Water (SW) System
- Tower Makeup Water (TMU) System

- Preventive Actions
  No actions are taken as part of the Selective Leaching Inspection to prevent aging effects or to mitigate aging degradation. Although the control of water chemistry may reduce selective leaching in treated water environments, no specific credit is taken for water chemistry control as part of this program.

- Parameters Monitored or Inspected
  The Selective Leaching Inspection will perform a combination of visual examination and hardness testing, or NRC approved alternative, of components within the scope of the program as a measure of loss of material due to selective leaching.

  The Selective Leaching Inspection activities will be conducted after the issuance of the renewed operating license and prior to the end of the current operating license, with sufficient time to implement programmatic oversight prior to the period of extended operation. The activities will be conducted no earlier than 5 years prior to the end of the current operating license, so that conditions are more representative of the conditions expected during the period of extended operation.

- Detection of Aging Effects
  The Selective Leaching Inspection will include provision for a combination of visual examination and hardness testing, or NRC approved alternative, of a sample of components with susceptible materials in environments conducive to the occurrence of selective leaching. The program will include the criteria for visual inspection and for hardness testing. The results of the inspections will be evaluated to determine the condition of the material. Engineering evaluation in conjunction with the corrective action program will determine whether components with degraded materials are capable of performing their intended functions.

  The aging management activities include: (a) determination of the sample size based on an assessment of materials of fabrication, environment and conditions, and operating experience; (b) identification of the inspection locations in the susceptible system or component; (c) determination of the examination technique, including acceptance criteria; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

  The results of the inspections will be evaluated against the acceptance criteria. Additional testing will be performed, as necessary, based on review of the inspection results.

- Monitoring and Trending
  No actions are taken as part of the Selective Leaching Inspection to monitor or trend inspection results. This is a one-time inspection activity used to determine if, and to what extent, further actions, including monitoring and trending, may be required. The inspection results will be evaluated through the site corrective action process.

- Acceptance Criteria
  The Selective Leaching Inspection will include acceptance criteria for visual inspections and for hardness testing, or NRC approved alternative. Inspection

results that do not meet the acceptance criteria will be entered into the corrective action program. The corrective action program includes provision for further evaluation of degraded materials and any necessary corrective actions.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Selective Leaching Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. However, plant design considerations address the potential for degradation of installed components through the application of materials suitable for the expected operating environments, and inspection methods will be consistent with accepted industry practices.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  Energy Northwest will follow the industry initiatives with respect to inspection for selective leaching, such as those being pursued by the EPRI and the NEI License Renewal Implementation Working Group. If a suitable alternative to hardness testing is identified prior to implementation of the inspection, Energy Northwest will seek NRC approval prior to its use.

  Some evidence of dezincification of the brass tubes in the main condenser was identified through visual inspection prior to startup (1982), and attributed to stagnant circulating water and a drop in pH. The condenser tubes, which are not in the scope of license renewal, were cleaned and there has been no recurrence of dezincification, although there are still residual effects of the original dezincification.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Selective Leaching Inspection will verify that selective leaching does not require management for the susceptible components, or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.48 Service Air System Inspection

Program Description

The Service Air System Inspection is a new one-time inspection that will detect and characterize the material condition of piping and valve bodies that are within the scope of license renewal in the Service Air System and are exposed to an "Air (internal)" environment. The Service Air System Inspection provides direct evidence as to whether, and to what extent, a loss of material due to general corrosion has occurred or is likely to occur in the subject components that could result in a loss of intended function.

Implementation of the Service Air System Inspection will ensure that the pressure boundary integrity of the subject components will be maintained consistent with the current licensing basis during the period of extended operation. Implementation of the inspection will also provide assurance (and confirmation) that the structural integrity of susceptible NSR components will be maintained such that the integrity of the attached safety-related piping is not impacted and will not result in the loss of any safety-related component intended functions during the period of extended operation.

NUREG-1801 Consistency

The Service Air System Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Service Air System Inspection detects and characterizes conditions relative to the following subject mechanical components to determine whether, and to what extent, degradation is occurring:

  - Loss of material due to general corrosion on steel piping and valve bodies exposed to an air (internal) environment.

  The Service Air System Inspection focuses on the portion of the Service Air System that forms the pressure boundary for containment penetration X93 and the connected piping subject to an air (internal) environment (i.e., compressed air) that performs a structural integrity function. The Service Air System Inspection provides symptomatic evidence of loss of material (due to general corrosion).

- Preventive Actions
  No actions are taken as part of the Service Air System Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Service Air System Inspection include wall thickness or visual evidence of internal surface degradation, as measures of loss of material. Inspections will be performed by qualified personnel using established NDE techniques.

- Detection of Aging Effects
  The Service Air System Inspection will use a combination of established volumetric (radiographic or ultrasonic testing) and visual (VT-3 or equivalent) examination techniques performed by qualified personnel on a portion of the subject Service Air System components as determined by engineering evaluation, to identify evidence of a loss of material, or to confirm a lack thereof.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Service Air System Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes increasing the inspection sample size and location if degradation is detected.

  Sample size will be determined by engineering evaluation of the materials of construction, environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using the corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective

action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Service Air System Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging mechanism is slow acting. Due to the fact that portable compressors without dryers have been used in the Service Air System, the system may not have always been reliably dry. This inspection will verify the presence (or absence) of general corrosion within the license renewal boundary of the Service Air System.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has identified no instances of loss of material related to the subject components.

  The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program is effective in managing the identified aging effects.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Service Air System Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

B.2.49 Small Bore Class 1 Piping Inspection

Program Description

The Small Bore Class 1 Piping Inspection will detect and characterize the conditions on the internal surfaces of small bore Class 1 piping components that are exposed to reactor coolant. The one-time inspection will provide physical evidence as to whether, and to what extent, cracking due to SCC or to thermal or mechanical loading has occurred in small bore Class 1 piping components. It will also verify, by inspections for cracking, that reduction of fracture toughness due to thermal embrittlement requires no additional aging management for small Class 1 CASS valve bodies. The Small Bore Class 1 Piping Inspection will be an evaluation and inspection with no actions to prevent or mitigate aging effects.

This one-time inspection is applicable to small bore ASME Code Class 1 piping components less than 4 inches nominal pipe size (NPS 4), which includes piping, fittings, branch connections, and valve bodies. The Small Bore Class 1 Piping Inspection includes visual and volumetric inspection of a representative sample of small bore Class 1 piping components. The inspection provides additional assurance that either age-related degradation of small bore ASME Code Class 1 piping components is not occurring or that the aging is insignificant, such that an additional aging management program is not warranted during the period of extended operation.

Columbia has not experienced cracking of small bore Class 1 piping solely due to stress corrosion or thermal and mechanical loading, and therefore this one-time inspection is appropriate.

The inspection will include a representative sample of the small bore Class 1 piping population, and, where practical, will focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)" will be considered in selecting the sample size and locations. Actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, and locations identified in NRC Information Notice (IN) 97-46. Volumetric examinations (including qualified destructive and/or nondestructive techniques) will be performed by qualified personnel following procedures that are consistent with Section XI of the ASME Code and 10 CFR 50, Appendix B.

Unacceptable inspection findings will be evaluated by the Columbia corrective action process using criteria in accordance with the ASME Code. The evaluation of indications will include determining the extent of condition by the expansion of the sample size when called for by the Code. Evaluation of inspection results may lead to the creation of a plant-specific AMP or may confirm that age-related degradation is either not occurring or is insignificant.

The Small Bore Class 1 Piping Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted during the portion of the fourth 10-year ISI interval that is prior to the period of extended operation.

The Small Bore Class 1 Piping Inspection will credit portions of the Inservice Inspection (ISI) Program. The Small Bore Class 1 Piping Inspection will verify the effectiveness of the BWR Water Chemistry Program in mitigating cracking of small bore piping and piping components.

NUREG-1801 Consistency

The Small Bore Class 1 Piping Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M35, "One-time Inspection of ASME Code Class 1 Small-Bore Piping."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Small Bore Class 1 Piping Inspection is a one-time inspection of a sample of ASME Code Class 1 piping and piping components less than NPS 4. The inspection will include measures to verify that unacceptable degradation is not occurring in Class 1 small bore piping and piping components (valve bodies), thereby confirming that an aging management program is not needed for the period of extended operation. See *Monitoring and Trending* below for a discussion of sample selection and inputs.

- Preventive Actions
  The Small Bore Class 1 Piping Inspection will be an evaluation and inspection with no actions to prevent or mitigate aging effects.

- Parameters Monitored or Inspected
  The Small Bore Class 1 Piping Inspection is a one-time inspection that will include volumetric examinations (destructive or nondestructive) performed by qualified personnel, using qualified volumetric examination techniques, and following procedures consistent with Section XI of the ASME Code and 10 CFR 50, Appendix B.

- Detection of Aging Effects
  This inspection will perform volumetric examinations on selected weld locations. Columbia has not experienced cracking of small bore Class 1 piping due to stress corrosion or thermal and mechanical loading, and therefore this one-time inspection is appropriate. Columbia has found cracking due to fatigue and growth of construction flaws of small bore piping. See *Operating Experience* below for discussion of site operating experience to date and lack of stress corrosion or thermal and mechanical loading induced cracks.

- Monitoring and Trending
  The inspection will include a representative sample of the small bore Class 1 piping population, and, where practical, will focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)" will be considered in selecting the sample size and locations. Actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, and locations identified in NRC Information Notice 97-46. Volumetric examinations (including qualified destructive and nondestructive techniques) will be performed by qualified personnel following procedures that are consistent with Section XI of the ASME Code and 10 CFR 50, Appendix B.

  Unacceptable inspection findings will be evaluated by the Columbia corrective action process. The Small Bore Class 1 Piping Inspection will require an increased sample size in response to unacceptable inspection findings. Evaluation of inspection results may lead to the creation of a plant-specific aging management program or may confirm that age-related degradation is either not occurring or is insignificant.

- Acceptance Criteria
  Unacceptable inspection findings will be evaluated by the Columbia corrective action process using criteria in accordance with the ASME Code. The evaluation of indications will include determining the extent of condition by the expansion of the sample size when called for by the Code. Evaluation of inspection results may lead to the creation of a plant-specific aging management program or may confirm that age-related degradation is either not occurring or is insignificant.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation. The Small Bore Class 1 Piping Inspection provides confirmation of material conditions near the period of extended operation as additional assurance that existing inspections, via the Inservice Inspection (ISI) Program, and control of water chemistry, via the BWR Water Chemistry Program, provide adequate management.

  Industry operating experience:

  > NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.
  >
  > Industry operating experience will be considered when implementing this one-time inspection. Plant operating experience for this activity will be gained as it is implemented near the period of extended operation, and will be factored into the activity. As such, operating experience assures that implementation of the Small Bore Class 1 Piping Inspection will confirm material condition relative to the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

  Columbia operating experience:

  > A review of Columbia operating experience identified other piping being examined by the same techniques and small bore piping that has experienced cracking due to fatigue.
  >
  > The Small Bore Class 1 Piping Inspection is a new one-time inspection activity for which plant operating experience has shown only one occurrence of stress corrosion cracking, and that as one of several contributors to fatigue cracking. The evaluations and examinations to be performed by this activity will use qualified volumetric examination techniques or destructive examination

techniques with demonstrated capability and a proven industry record to detect cracking in piping weld and base metal.

Several cracks due to vibration induced fatigue or construction flaws occurred in small bore piping during the early years of plant life. Design changes were instituted to reduce vibration and sources of cyclic loading. The occurrence of these small bore leaks has decreased in recent years showing the effectiveness of the actions being taken. No instances of stress corrosion cracking or low cycle fatigue cracking as the sole failure mechanism were identified. A single instance of small bore Class 1 piping failure related to stress corrosion cracking was found in 1993, which also involved other contributing factors that led to fatigue cracking. The weld was removed and configuration was changed to address the vibration and cyclic loading considerations. No other instances of stress corrosion cracking of small bore Class 1 piping have been identified.

The Small Bore Class 1 Piping Inspection will be developed based on relevant plant and industry operating experience. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the one-time inspection confirms material condition such that the existing program (ISI) is demonstrated to be effective in managing the identified aging effects, or a new aging management program will be developed.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

The Small Bore Class 1 Piping Inspection will verify that cracking due to stress corrosion and mechanical loading, and cracking due to reduction of fracture toughness are not occurring or are insignificant, such that an aging management program is not required during the period of extended operation. The Small Bore Class 1 Piping Inspection will provide reasonable assurance that the aging effects are not occurring such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.50 Structures Monitoring Program

Program Description

The Structures Monitoring Program is part of the Maintenance Rule program. It is an existing program that is designed to ensure that age-related degradation of the plant structures and structural components within its scope is managed to ensure that each structure and structural component retains the ability to perform its intended function. The Maintenance Rule program is comprised of many existing monitoring and assessment activities, which collectively address potential and actual degradation conditions and their effects upon the reliability of the structures and components that are within the scope of the program.

The Structures Monitoring Program implements provisions of the Maintenance Rule, 10 CFR 50.65, which relate to structures, masonry walls, and water-control structures. It conforms to the guidance contained in Regulatory Guide (RG) 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants", and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Concrete and masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program.

The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection and the Masonry Wall Inspection.

Since protective coatings are not relied upon to manage the effects of aging for structural components included in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance.

Aging effects identified within the scope of the Structures Monitoring Program are detected by visual inspection of external surfaces prior to the loss of the structure's or component's intended functions.

The Structures Monitoring Program provides reasonable assurance that the effects of aging are adequately managed to assure that plant structures and structural components' intended function will be performed consistent with the current licensing basis for the period of extended operation.

NUREG-1801 Consistency

The Structures Monitoring Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S6, "Structures Monitoring Program."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope –**

  Include and list the following structures within the scope of license renewal that credit the Structures Monitoring Program for aging management:

  - Circulating Water Basin
  - Circulating Water Pump House
  - Condensate Storage Tanks Foundations and Retaining Area
  - Cooling Tower Basins
  - Diesel Generator Building
  - Duct Banks and Manholes
  - Fire Water Bladder Tank (FP-TK-110) Embankment
  - Fresh Air Intake Structure No. 1 and 2
  - Hydrogen Storage and Supply Facility
  - Makeup Water Pump House
  - Primary Containment (includes drywell, biological shield wall, reactor pedestal, sacrificial shield wall, and internal structural components)
  - Radwaste Control Building
  - Reactor Building (includes secondary containment, reactor cavity, refueling area, new fuel storage vault, release stack)
  - Service Building
  - Spray Pond 1A and 1B
  - Standby Service Water Pump House 1A and 1B
  - Station Blackout component foundations and structures in the yard (includes startup transformers TR-S, backup transformer TR-B, Ashe A809 breaker, oil circuit breaker (OCB) E-CB-TRB, and Ashe relay house)
  - Transmission Towers

- Turbine Generator Building
- Water Filtration Building

Enhancements to this element for the Structures Monitoring Program also include enhancements that are being made to the Water Control Structures Inspection. See the Water Control Structures Inspection for required enhancement details.

- **Parameters Monitored or Inspected –**

Specify that if a below grade structural wall or structural component becomes accessible through excavation; a follow-up action is initiated for the responsible engineer to inspect the exposed surfaces for age-related degradation prior to backfilling.

Identify that the term "structural component" for inspection includes component types that credit the Structures Monitoring Program for aging management.

Include the potential degradation mechanism checklist in the procedural documents. The checklist also requires enhancement to include aging effect terminology (e.g., loss of material, cracking, change in material properties, and loss of form).

Specify that the responsible engineer shall review site groundwater and raw water testing results for pH, chlorides, and sulfates prior to inspection to validate that the below-grade or raw water environments remain non-aggressive during the period of extended operation. Chemistry data shall be obtained from Columbia's chemistry and environmental departments. Groundwater chemistry data shall be collected at least once every four years. The time of data collection shall be staggered from year to year (summer-winter-summer) to account for seasonal variations in the environment.

Enhancements to this element for the Structures Monitoring Program also include enhancements that are being made to the Water Control Structures Inspection and the Masonry Wall Inspection. See the Water Control Structures Inspection and the Masonry Wall Inspection for required enhancement details.

Operating Experience

The Structures Monitoring Program has been effective in managing the identified aging effects. Although actual experience with Structures Monitoring Program inspections is limited, recent inspection results have shown that plant structures are maintained in good condition. No significant failures have occurred in any Columbia structure to date.

Normal deterioration due to the effects of aging has been identified and effectively managed under the site maintenance program.

Visual examinations conducted by the Structures Monitoring Program have found general corrosion on steel components and concrete cracking, flaking, and scaling. Some of the currently identified concrete surface conditions have existed since original construction. These conditions are the results of typical construction practices permitted by the original specifications and design criteria. They include small shrinkage cracks, minor construction joint voids, surface irregularities, and similar conditions determined to be minor degradation that did not require further evaluation. Inspected structures are in good condition and are capable of performing their design functions.

Specific examples of age-related degradation identified by the Structures Monitoring Program include:

- Circulating water pump house - Minor leaching observed on the concrete pad near the interface with the siding, cracks in the wall along joints due to stresses caused by a hanger attached to the wall above door, corrosion on the lower section of various door frames, and minor cracking of concrete damwork around the intake bays.
- Turbine generator building - Air in-leakage noted at north exterior turbine generator building wall panels, degraded roof membrane, and minor water in-leakage from roof above.
- Radwaste control building - Some areas of concrete spalling in the switchgear rooms probably from racking breakers in and out, delaminated floor coatings, and punctured roof membrane from screws.
- Wetwell - Support steel has layer of corrosion products, condition was unchanged from previous inspections. The condition was reviewed by the material group which determined the condition of the wetwell and containment liner to be acceptable.
- Main steam tunnel - Some flaking of coating on the overhead horizontal panels, the condition was unchanged from previous inspections and determined to be acceptable.

The overall Maintenance Rule program is comprised of many existing monitoring and assessment activities that collectively address potential and actual degradation conditions. The Maintenance Rule program screens all condition reports written at Columbia. When a condition report addresses a structure issue it is reviewed by a system engineer for evaluation of a functional failure. The screening results are captured in the Maintenance Rule program periodic assessment. The review of structural-related condition reports to determine functional failure includes determination of whether failures were maintenance preventable. A review of the Maintenance Rule program periodic assessments did not identify any age-related functional failures related to structures. Two non-age related functional failures identified were that the Reactor Building crane was parked without the tornado latches installed and a 10 CFR 21 notice from Whiting Crane Corporation regarding a weld defect on the Reactor Building crane main trolley.

A recent condition report documents a surface flaw noted in the concrete of the west exterior wall of the Reactor Building. The surface flaw appears to have existed for a significant period of time with no apparent adverse effects on secondary containment or the Reactor Building structure.

NRC Unresolved Item (URI) 05000397/2007005-02 was issued in February of 2008. This URI identified that Columbia had not performed nor scheduled condition monitoring, inspection, or preventative maintenance (since receiving an operating license in 1983) of the submerged portion of the suppression chamber, the standby service water spray ponds, or the condensate storage tanks. The URI stated that although the licensee performed some monitoring of these structures, failure to perform monitoring of the submerged portion of these structures could result in undetected cracks or leakage that could prevent them from meeting their design basis functions. This URI was documented in a condition report that is currently being resolved under the corrective action process with closure information expected near the time of the LRA submittal.

The Structures Monitoring Program provides reasonable assurance that aging effects are being managed. This has been demonstrated through inspection reports, program health reports, periodic assessments, and the corrective action program.

The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Structures Monitoring Program, with enhancements, will be capable of detecting and managing aging effects for structures within the scope of license renewal. The continued implementation of the Structures Monitoring Program, with the required enhancements, provides reasonable assurance that the effects of aging will be managed so that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.51 Supplemental Piping/Tank Inspection

Program Description

The Supplemental Piping/Tank Inspection is a new one-time inspection that will detect and characterize the material condition of steel, gray cast iron, and stainless steel components that are exposed to moist air environments, particularly the aggressive alternate wet and dry environment that exists at air-water interfaces or air spaces of susceptible piping and tanks. The inspection provides direct evidence as to whether, and to what extent, loss of material due to crevice, galvanic, general, and pitting corrosion, or MIC has occurred or is likely to occur that could result in a loss of intended function of the subject components.

Implementation of the Supplemental Piping/Tank Inspection will ensure that the pressure boundary integrity of susceptible safety-related components is maintained consistent with the current licensing bases during the period of extended operation. Implementation of the inspection will also ensure that the structural integrity of susceptible NSR components will be maintained such that spatial interactions (e.g., leakage) will not result in the loss of any safety-related component intended functions during the period of extended operation.

NUREG-1801 Consistency

The Supplemental Piping/Tank Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- *Scope of Program*
  The scope of the Supplemental Piping/Tank Inspection includes the internal and external surfaces of steel, gray cast iron, and stainless steel components at air-water interfaces and other susceptible locations in the following systems:

  - Condensate (Nuclear) (COND) System
  - Containment Vacuum Breakers (CVB)
  - Diesel Cooling Water (DCW) System
  - Equipment Drains Radioactive (EDR) System

- Fire Protection (FP) System
- Floor Drain (FD) System
- Floor Drain Radioactive (FDR) System
- Fuel Pool Cooling (FPC) System
- High Pressure Core Spray (HPCS) System
- Low Pressure Core Spray (LPCS) System
- Main Steam (MS) System
- Miscellaneous Drain (MD) System
- Process Sampling Radioactive (PSR) System
- Reactor Building Outside Air (ROA) System
- Reactor Closed Cooling Water (RCC) System
- Reactor Core Isolation Cooling (RCIC) System
- Residual Heat Removal (RHR) System
- Standby Liquid Control (SLC) System
- Standby Service Water (SW) System
- Tower Makeup Water (TMU) System

A representative sample of components at susceptible locations will be examined for evidence of loss of material (due to crevice, galvanic, general, or pitting corrosion, or MIC), or to confirm a lack thereof.

The Supplemental Piping/Tank Inspection focuses on a limited but representative sample population of subject components at susceptible locations to be defined in the implementing documents, to include external piping surfaces and internal tank and piping surfaces at air-water interfaces. The inspections provide symptomatic evidence of loss of material at the other susceptible, but possibly inaccessible, locations (such as internal surfaces of piping) due to the similarities in materials and environmental conditions.

- Preventive Actions
  No actions are taken as part of the Supplemental Piping/Tank Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Supplemental Piping/Tank Inspection include wall thickness or visual evidence of internal and external surface degradation, as measures of loss of material. Inspections will be performed by qualified personnel

using established NDE techniques (i.e., ultrasonic examination). Visual inspection of tank internals for evidence of corrosion and corrosion products may be performed.

- Detection of Aging Effects
  The Supplemental Piping/Tank Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on a sample population of subject components to identify evidence of a loss of material.

  A sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and the lowest design margins.

  The Supplemental Piping/Tank Inspection will be conducted within the 10-year period prior to the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and location if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and of operating experience (e.g., time in-service, most susceptible locations, lowest design margins, etc.). Inspection findings that do not meet the acceptance criteria will be evaluated using the corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The Supplemental Piping/Tank Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging effect. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging mechanism is slow acting.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience did not identify any aging effects that were attributed to air-water interfaces or other susceptible locations. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the program is effective in managing the identified aging effects.

Required Enhancements

Not applicable, this is a new activity.

Conclusion

Implementation of the Supplemental Piping/Tank Inspection will verify that there are no aging effects requiring management for the subject components or will identify corrective actions, possibly including programmatic oversight, to be taken to ensure that the component intended functions of the subject components will be maintained consistent with the current licensing basis during the period of extended operation, and that spatial interactions (e.g., leakage) will not result in loss of safety-related component intended functions during the period of extended operation.

B.2.52 Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

Program Description

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will manage reduction of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals. This program augments the visual inspection of the reactor vessel internals done in accordance with the ASME Code, Section XI, Subsection IWB, Category B-N-2 (B-N-2 versus B-N-3 as BWRs do not have B-N-3 components) and in accordance with the BWRVIP program documents. This program will consist of (a) identification of susceptible components followed by aging management accomplished through either (b) a component-specific evaluation or (c) a supplemental examination. The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a condition monitoring program with no actions to prevent or mitigate aging effects. The program will be implemented by analyses and augmenting of the Inservice Inspection program completed prior to the period of extended operation.

(a) identification of susceptible components

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will screen reactor vessel internals components to determine which components are susceptible to reduction of fracture toughness due to the combination of thermal aging and neutron embrittlement on the basis of casting method, molybdenum content, and ferrite content.

Columbia has no cast austenitic stainless steel reactor coolant pressure boundary components that are exposed to high levels of neutron irradiation; therefore there are no pressure boundary components in this program.

(b) a component-specific evaluation

Components identified as susceptible by the screening will be individually evaluated for susceptibility based on neutron fluence and component material properties following the guidelines in NUREG/CR-4513, Revision 1. Component-specific evaluations may include a mechanical loading assessment. If no component-specific evaluation is performed, or if the evaluation does not eliminate the need for inspection, the components will be inspected

(c) a supplemental examination

Examination techniques will be developed considering the recommendations of NUREG-1801 Section XI.M13. As determined necessary, nondestructive examinations (including visual, ultrasonic, and surface techniques) will be performed by qualified personnel following procedures consistent with ASME Section XI and 10 CFR 50, Appendix B. Supplemental examination of screened components will be performed as augmented inspections in the Columbia 10-year Inservice Inspection (ISI) program.

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new aging management program that will be implemented prior to the period of extended operation.

The program credits portions of the Inservice Inspection (ISI) Program (ASME Code Section XI, Subsection IWB, Category B-N-2) and the BWR Vessel Internals Program (jet pump inspections per BWRVIP-41 Revision 1 and control rod guide tubes and fuel support pieces per BWRVIP-47A).

NUREG-1801 Consistency

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will screen reactor vessel internals components to determine which components are susceptible to reduction of fracture toughness due to the combination of thermal aging and neutron embrittlement on the basis of casting method, molybdenum content, and ferrite content. For such components, the program will include either a supplemental examination, based on the neutron fluence to which the component has been exposed, as part of the Inservice Inspection (ISI) Program or the BWR Vessel Internals Program during the license renewal term, or a component-specific evaluation to determine its susceptibility to reduction of fracture toughness.

  Columbia has no cast austenitic stainless steel reactor coolant pressure boundary components that are exposed to high levels of neutron irradiation; therefore there are no pressure boundary components in this program.

- Preventive Actions
  The Columbia program will be an evaluation and inspection program with no actions to prevent or mitigate aging effects. The program will be implemented by analyses and augmenting of the Inservice Inspection program. (See *Detection of Aging Effects* below.)

- Parameters Monitored or Inspected
  The Columbia program will screen components based on material properties as discussed under the program *Scope* element above. Components identified as susceptible by the screening will be individually evaluated for susceptibility based on neutron fluence and component material properties following the guidelines in NUREG/CR-4513, Revision 1. Those components evaluated to require inspection will be inspected by augmentation of the Inservice Inspection program as discussed under *Detection of Aging Effects* below.

- Detection of Aging Effects
  The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will first screen components as discussed under *Scope* above, then evaluate those components screened as susceptible to reduction of fracture toughness as discussed above under *Parameters Monitored or Inspected*. Those components, or portions of components, determined to be susceptible to cracking from thermal aging and radiation embrittlement may then be given a component-specific evaluation, including a mechanical loading assessment. If no component-specific evaluation is performed, or if the evaluation does not eliminate the need for inspection, the components will be inspected by augmenting the Inservice Inspection (ISI) Program or the BWR Vessel Internals Program. Supplemental inspections will be added to the 10-year ISI Program Plan for the interval that includes the beginning of the period of extended operation. Examination techniques will be developed considering the recommendations of NUREG-1801 Section XI.M13. As determined necessary, nondestructive examinations (including visual, ultrasonic, and surface techniques) will be performed by qualified personnel following procedures consistent with ASME Section XI and 10 CFR 50, Appendix B.

  The activities associated with component screening, susceptibility evaluation, component-specific evaluation, augmenting of the Inservice Inspection (ISI) Program or the BWR Vessel Internals Program, and adding supplemental inspections to the 10-year ISI Program Plan will be completed prior to the period of extended operation.

- Monitoring and Trending
  The Inservice Inspection (ISI) Program already inspects in accordance with ASME Section XI and IWB-2400. Any augmented inspections resulting from the screening and evaluation discussed above under *Scope* and *Parameters Monitored or*

Inspected will be added to the Inservice Inspection (ISI) Program or the BWR Vessel Internals Program as discussed under *Detection of Aging Effects.*

- Acceptance Criteria
  There are no pressure boundary components in this program. Acceptance criteria for flaws detected in CASS components will be developed based on the ASME Section XI criteria and the BWRVIP guidance applicable to the component under evaluation. Flaw evaluation for CASS components with greater than 25 percent ferrite content will be developed on a case-by-case basis using fracture toughness data.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  Based on review of plant-specific and industry operating experience, the identified aging effects require management for the period of extended operation.

  Industry operating experience:

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  Industry operating experience will be considered when implementing this program. Plant operating experience for this program will be gained as it is implemented during the period of extended operations, and will be factored into the program. As such, operating experience assures that implementation of the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Columbia operating experience:

> The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program for which there is no site-specific operating experience. A review of Columbia operating experience identified no degradation of CASS vessel internals Vessel internals has been inspected and some indications found, such as core shroud cracking and jet pump set screw gaps, and those indications have been dispositioned. However, no indications have been found for CASS vessel internals components.

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will be developed based on relevant plant and industry operating experience. The site corrective action program and an ongoing review of industry operating experience will be used to ensure that the new program is effective in managing the identified aging effects.

Required Enhancements

Not applicable, this is a new program.

Conclusion

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will be capable of managing reduction of fracture toughness for cast austenitic stainless steel components of the reactor vessel internals. The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will provide reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.53 Water Control Structures Inspection

Program Description

The Water Control Structures Inspection is implemented as part of the Structures Monitoring Program conducted for the Maintenance Rule.

The Water Control Structures Inspection is an existing condition monitoring program for detecting aging and age-related degradation of the Seismic Category I Spray Ponds and the Standby Service Water Pump Houses. It also inspects the Seismic Category II Circulating Water Pump House (including the circulating water basin), the Makeup Water Pump House, and the cooling tower basins.

Columbia is not committed to RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." However, enhancements pertaining to water control structure inspection elements from RG 1.127 Revision 1 will be incorporated into the Structures Monitoring Program consistent with NUREG-1801, Section XI.S7.

NUREG-1801 Consistency

The Water Control Structures Inspection is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope, Parameters Monitored or Inspected –**

  Include and list the water control structures within the scope of license renewal. Include the RG 1.127 Revision 1 inspection elements for water control structures, including submerged surfaces. Ensure descriptions of concrete conditions conform with the appendix to the American Concrete Institute (ACI) publication, ACI 201, "Guide for Making a Condition Survey of Concrete in Service." Add a recommendation to use photographs for comparison of previous and present conditions. Add a requirement for the documentation of new or progressive problems as a part of the inspection program.

Operating Experience

The Water Control Structures Inspection has been effective in managing the identified aging effects. Visual inspections conducted by the Water Control Structures Inspection, implemented as part of the Structures Monitoring Program, have found no age-related problems.

The general structural condition of Standby Service Water Pump Houses "A" and "B" and their associated spray ponds is good. No adverse conditions or deficiencies (cracking, spalling, or honeycombs) were noted during the inspection of concrete structural elements (walls, slabs, beams, etc.) that would affect the structural integrity of either pump house or spray pond. Equipment anchorages were secured. No degraded conditions (bent or twisted members, cracked welds, loose or missing fasteners, etc) were identified for steel members. The "saddle" supports for the ring header were noted to have the coating delaminating in places. However, there were only minor amounts of corrosion products at those locations (i.e., not a structural concern). Pipe supports on spray pond walls were in good shape with all fasteners installed and tight. Doors and frames did not show any evidence of a degraded condition. There were no signs of moisture intrusion from the roof above and no signs of gross deficiencies (spalling, cracking, honeycombs) found from below. There were no obvious deficiencies identified with the crane structural frames. The rails appeared in good physical condition with no obvious signs of degradation such as bent or deformed rails. The Standby Service Water Pump Houses and the Spray Ponds are capable of performing their intended design function as the ultimate heat sink in response to accident conditions.

NRC Unresolved Item (URI) 05000397/2007005-02 was issued in February of 2008. This URI identified that Columbia had not performed nor scheduled condition monitoring, inspection, or preventative maintenance (since receiving an operating license in 1983) of the submerged portion of the suppression chamber, the standby service water spray ponds, or the condensate storage tanks. The URI stated that although the licensee performed some monitoring of these structures, failure to perform monitoring of the submerged portion of these structures could result in undetected cracks or leakage that could prevent them from meeting their design basis functions. This URI was documented in a condition report that is currently being resolved under the corrective action process with closure information expected near the time of the LRA submittal.

The general conditions noted for the Circulating Water Pump House (including circulating water basin) and the cooling tower basins, including the structural components within the structures, was acceptable. Minor leaching was observed in the Circulating Water Pump House on a concrete pad near the interface with the siding, in addition to cracks in the wall along joints due to stresses caused by a hanger attached to the wall above the door, corrosion on the lower section of various door frames, and minor cracking of concrete damwork around the intake bays. No condition was deemed to require immediate or long-term resolution. Minor "cosmetic" imperfections with the concrete (blemishes, cure voids, surface cracks, etc.) were noted. These minor imperfections will continue to be monitored, but they currently pose no concern to the structural condition of the area.

The Water Control Structures Inspection, implemented as part of the Structures Monitoring Program, provides reasonable assurance that aging effects are being managed for Columbia's water control structures. This has been demonstrated through inspection reports, program health reports, and the corrective action program.

The site corrective action program and ongoing review of industry operating experience will be used to ensure that the program continues to be effective in managing the identified aging effects.

Conclusion

The Water Control Structures Inspection with enhancements, as part of the Structures Monitoring Program, will be capable of detecting and managing aging effects for structures within the scope of license renewal. The continued implementation of the Water Control Structures Inspection, with the required enhancements, provides reasonable assurance that the effects of aging will be managed so that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

APPENDIX C

RESPONSE TO BWRVIP APPLICANT ACTION ITEMS

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BWRVIP Report Applicant Action Items

The following Boiling Water Reactor Vessel Internals Project (BWRVIP) documents credited for Columbia license renewal have NRC safety evaluation reports (SERs).

- Table C-1 — BWRVIP-18-A - BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines
- Table C-2 — BWRVIP-25 - BWR Core Plate Inspection and Flaw Evaluation Guidelines
- Table C-3 — BWRVIP-26-A - BWR Top Guide Inspection and Flaw Evaluation Guidelines
- Table C-4 — BWRVIP-27-A - BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines
- Table C-5 — BWRVIP-38 - BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- Table C-6 — BWRVIP-41 - BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines
- Table C-7 — BWRVIP-42-A - LPCI Coupling Inspection and Flaw Evaluation Guidelines
- Table C-8 — BWRVIP-47-A - BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
- Table C-9 — BWRVIP-48-A - Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines
- Table C-10 — BWRVIP-49-A - Instrument Penetration Inspection and Flaw Evaluation Guidelines
- Table C-11 — BWRVIP-74-A - BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal
- Table C-12 — BWRVIP-116 - BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal

License renewal Applicant Action Items (AAIs) identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. A plant-specific response is provided for each AAI. The table for BWRVIP-116 (Table C-12) contains required modifications to the BWRVIP Integrated Surveillance Program (ISP) called for in the SER; however, the SER does not contain any applicant action items. BWRVIP-76 is not included because the SER has not yet been issued. BWRVIP reports without SERs for license renewal have no AAIs; therefore, no tables are provided.

Table C-1

BWRVIP-18-A BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-18 report to manage the effects of aging on the functionality of the core spray internals during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within the BWRVIP-18 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor pressure vessel components or other information presented in the report, such as materials of construction, will have to be identified by the LR applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-18-A guidelines. Therefore, Columbia is bounded by the BWRVIP-18-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-18 report for the core spray internals shall ensure that the programs and activities specified as necessary in the BWRVIP-18 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-1

BWRVIP-18-A BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix C to the BWRVIP-18 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the core spray internals as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-18 report for the core spray internals shall ensure that the inspection strategy described in the BWRVIP-18 report does not conflict with or result in any changes to their technical specifications. If technical specification changes do result, then the applicant must ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-18-A report.
(4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components.	The only TLAA issues identified for the reactor pressure vessel (RPV) internal core spray components were the CUFs in LRA Table 4.3-4 for the core spray sparger and core spray piping. Disposition of these TLAAs is discussed in Section 4.3.2.1 of the LRA.

Table C-2

BWRVIP-25 BWR Core Plate Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the BWRVIP-25 report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-25 report to manage the effects of aging on the functionality of the core plate assembly during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMPs within the BWRVIP-25 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-25 guidelines. Therefore, Columbia is bounded by the BWRVIP-25 report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-25 report for the core plate will ensure that the programs and activities specified as necessary in the BWRVIP-25 report are summarily described in the FSAR supplement.	BWRVIP-25 requires inspection of the core plate rim hold-down bolts for those plants that use these bolts to prevent lateral motion of the core plate. As described in response to AAI #4, Columbia has wedges installed to perform this function. Thus Columbia complies with the second option of BWRVIP-25, to install wedges rather than inspect the core plate rim hold-down bolts. Therefore, no programs or activities are required and no summary description is provided in the FSAR supplement, contained in Appendix A of the LRA.

Table C-2

BWRVIP-25 BWR Core Plate Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix B to the BWRVIP-25 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the core plate as a result of its AMR and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-25 report for the core plate will ensure that the inspection strategy described in the BWRVIP-25 report does not conflict with or result in any changes to their technical specifications (TS). If TS changes do result, then the applicant must ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-25 report.
(4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	Stress relaxation of the core plate rim hold-down bolts is not a TLAA for Columbia. During original fabrication of the Columbia reactor internals, wedges were installed to prevent lateral motion of the core plate, and Columbia does not require the core plate rim hold-down bolts for this function.
(5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	BWRVIP-25 requires inspection of the core plate rim hold-down bolts for those plants that use these bolts to prevent lateral motion of the core plate. As described in response to AAI #4, Columbia has wedges installed to perform this function. Thus Columbia complies with the second option of BWRVIP-25, to install wedges rather than inspect the core plate rim hold-down bolts.

Table C-3

BWRVIP-26-A BWR Top Guide Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-26 report to manage the effects of aging on the functionality of the top guide structure during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMPs within the BWRVIP-26 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-26-A guidelines. Therefore, Columbia is bounded by the BWRVIP-26-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-26 report for the top guide system shall ensure that the programs and activities specified as necessary in the BWRVIP-26 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-3

BWRVIP-26-A BWR Top Guide Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix C to the BWRVIP-26 report, the BWRVIP stated that there are no generic changes or additions to technical specifications (TS) associated with the top guide as a result of its AMR and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-26 report for the top guide shall ensure that the inspection strategy described in the BWRVIP-26 report does not conflict or result in any changes to their TS. If TS changes do result, then the applicant should ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-26-A report.
(4) Due to IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.	Accumulated neutron fluence for the top guide is not a TLAA for Columbia. The top guide has exceeded the threshold fluence levels for IASCC identified in BWRVIP-26-A. The aging effect is managed per the inspection recommendations in BWRVIP-183, which includes the inspections recommended by NUREG-1801 for the period of extended operation.

Table C-4

BWRVIP-27-A BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP report to manage the effects of aging on the functionality of the DP/SLC vessel penetration/nozzle and safe-end extensions during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	Columbia does not inject standby liquid control (SLC) through the SLC differential pressure (DP) nozzle, rather Columbia injects through the high pressure core spray line. Thus, consistent with Section 1.1 of BWRVIP-27-A, this BWRVIP document does not apply to Columbia.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-27 report for the DP/SLC vessel penetration/nozzle and safe end extensions shall ensure that the programs and activities specified as necessary in the BWRVIP-27 document are summarily described in the FSAR supplement.	As described in response to AAI #1, BWRVIP-27-A does not apply to Columbia. Therefore, no programs or activities are required and no summary description is provided in the FSAR supplement, contained in Appendix A of the LRA.

Table C-4

BWRVIP-27-A BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix B to the BWRVIP-27 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the DP/SLC vessel penetration/nozzle and safe-end extensions as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP-27 for the DP/SLC vessel penetration/nozzle and safe-end extensions shall ensure that the inspection strategy described in the BWRVIP-27 document does not conflict with or result in any changes to their technical specifications. If technical specification changes do result, then the applicant must ensure that those changes are included in its application for license renewal.	As described in response to AAI #1, BWRVIP-27-A does not apply to Columbia. Therefore, no technical specification changes are required for the inspection strategy described in the BWRVIP-27-A report.
(4) Due to the susceptibility of the subject components to fatigue, applicants referencing the BWRVIP-27 report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.	As described in response to AAI #1, BWRVIP-27-A does not apply to Columbia. The only TLAA identified for the standby liquid control differential pressure (SLC/DP) line is the cumulative usage factor for the (core DP) nozzle stub tube. This is addressed in Section 4.3.1 (Table 4.3-3) of the LRA.

Table C-5

BWRVIP-38 BWR Shroud Support Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-38 report to manage the effects of aging on the functionality of the shroud support components during the period of extended operation, including actions planned to inspect welds that are presently inaccessible. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within the BWRVIP-38 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-38 guidelines. Therefore, Columbia is bounded by the BWRVIP-38 report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) An FSAR supplement is required by 10 CFR 54.21 (d) for the facility and must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-38 report for the shroud support shall ensure that the programs and activities specified as necessary in the BWRVIP-38 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-5

BWRVIP-38 BWR Shroud Support Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) Each application for license renewal is required by 10 CFR 54.22 to include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix B to the BWRVIP-38 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the shroud support as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-38 report for the shroud support shall ensure that the inspection strategy described in the BWRVIP-38 report does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-38 report.

Table C-6

BWRVIP-41 BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the BWRVIP-41 report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-41 report to manage the effects of aging on the functionality of the jet pump components during the period of extended operation, including actions planned to mitigate the issue concerning the inspection of welds that are presently inaccessible, and the thermal and/or neutron embrittlement TLAA. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within the BWRVIP-41 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-41 guidelines. Therefore, Columbia is bounded by the BWRVIP-41 report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-41 report for the jet pump components shall ensure that the programs and activities specified as necessary in the BWRVIP-41 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-6

BWRVIP-41 BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix A to the BWRVIP-41 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the jet pump assembly as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-41 report for the jet pump assembly shall ensure that the inspection strategy described in the BWRVIP-41 report does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-41 report.

Table C-7

BWRVIP-42-A LPCI Coupling Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the BWRVIP-42 report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-42 report to manage the effects of aging on the functionality of the LPCI coupling during the period of extended operation, including actions planned to inspect welds that are presently inaccessible. If corrective actions are necessary, the applicant shall either commit to follow the guidance in the staff-approved BWRVIP-56 report, "LPCI Coupling Repair Design Criteria," or describe the process that will be utilized to repair the LPCI couplings if needed. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within the BWRVIP-42 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC notified, for any deviation from the guidelines. Columbia deviation DD-06 documents that the re-inspection of the first low-pressure coolant injection (LPCI) coupling was not completed as scheduled. The LPCI coupling was inspected during the last refueling outage (R19) and the other couplings will be inspected as originally scheduled; completing the first round of re-inspections required by BWRVIP-42-A. Therefore, Columbia is bounded by the BWRVIP-42-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.

Table C-7

BWRVIP-42-A LPCI Coupling Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-42 report for the LPCI coupling internals shall ensure that the programs and activities specified as necessary in the BWRVIP-42 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.
(3) 10 CFR 54.22 requires each applicant for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix A to the BWRVIP-42 report, the BWRVIP stated that there are no generic changes or additions to technical specifications associated with the LPCI coupling as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-42 report for the LPCI coupling internals shall ensure that the inspection strategy described in the BWRVIP-42 report does not conflict with or result in any changes to their technical specifications. If technical specification changes do result, then the applicant must ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-42-A report.
(4) Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components.	The only TLAA identified for the LPCI coupling is the cumulative usage factor for the coupling. This is addressed in Section 4.3.2 (Table 4.3-4) of the LRA.

Table C-7

BWRVIP-42-A LPCI Coupling Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(5) The BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR applicant notify the NRC of actions planned. Applicants referencing the BWRVIP-42 report for license renewal should identify this action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff.	In accordance with the BWR Vessel Internals Program, Columbia will implement the additional inspection requirements of BWRVIP-42-A once those requirements are approved by the NRC staff.

Table C-8

BWRVIP-47-A BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The LR applicant is to verify that its plant is bounded by the BWRVIP-47 report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-47 report to manage the effects of aging on the functionality of the lower plenum during the period of extended operation. LR applicants will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMPs within the BWRVIP-47 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-47-A guidelines. Therefore, Columbia is bounded by the BWRVIP-47-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for LR referencing the BWRVIP-47 report for the lower plenum shall ensure that the programs and activities specified as necessary in the BWRVIP-47 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-8

BWRVIP-47-A BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each LR application include any TS changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the LR application. In its Appendix A to the BWRVIP-47 report, the BWRVIP stated that there are no generic changes or additions to TSs associated with the lower plenum as a result of its AMR and that the applicant will provide the justification for plant-specific changes or additions. Those LR applicants referencing the BWRVIP-47 report for the lower plenum shall ensure that the inspection strategy described in the BWRVIP-47 report does not conflict or result in any changes to their TSs. If technical specification changes do result, then the applicant should ensure that those changes are included in its LR application.	No technical specification changes are required for the inspection strategy described in the BWRVIP-47-A report.
(4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	The only TLAAs identified for the lower plenum are the cumulative usage factors for the control rod drive (CRD) housings, CRD stub tubes, and incore housing penetrations. These are addressed in Section 4.3.1 (Table 4.3-3) of the LRA.

Table C-9

BWRVIP-48-A Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the BWRVIP-48 report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP-48 report to manage the effects of aging on the functionality of the bracket attachments during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within the BWRVIP-48 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented, and the NRC to be notified, for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-48-A guidelines. Therefore, Columbia is bounded by the BWRVIP-48-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the BWRVIP-48 report for the bracket attachments shall ensure that the programs and activities specified as necessary in the BWRVIP-48 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-9

BWRVIP-48-A Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix A to the BWRVIP-48 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with the bracket attachments as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the BWRVIP-48 report for the bracket attachments shall ensure that the inspection strategy described in the BWRVIP-48 report does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-48-A report.

Table C-10

BWRVIP-49-A Instrument Penetration Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP report to manage the effects of aging on the functionality of the reactor vessel instrument penetrations during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-49-A guidelines. Therefore, Columbia is bounded by the BWRVIP-49-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the BWRVIP- 49 report for the instrument penetrations shall insure that the programs and activities specified as necessary in the BWRVIP-49 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-10

BWRVIP-49-A Instrument Penetration Inspection and Flaw Evaluation Guidelines	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. In its Appendix A to the BWRVIP-49 report, the BWRVIP stated that there are no generic changes or additions to technical specification associated with instrument penetrations as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing BWRVIP-49 for the instrument penetrations shall ensure that the inspection strategy described in the BWRVIP-49 document does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its application for license renewal.	No technical specification changes are required for the inspection strategy described in the BWRVIP-49-A report.

Table C-11

BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
(1) The LR applicant is to verify that the BWRVIP-74 report is applicable to its plant. Further, the LR applicant is to commit to programs described as necessary in the BWRVIP-74 report to manage the effects of aging on the functionality of the RPV components during the period of extended operation. LR applicants will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMP within the BWRVIP-74 report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the LR applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWR Vessel Internals Program requires the inspection and evaluation guidelines of this BWRVIP report to be implemented at Columbia. Site procedures require a technical justification to be documented for any deviation from the guidelines. Columbia has not identified any deviation from the BWRVIP-74-A guidelines. Therefore, Columbia is bounded by the BWRVIP-74-A report. Columbia commits to programs described as necessary in the BWRVIP report to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50 Appendix B.
(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those LR applicants referencing the BWRVIP-74 report for the RPV components shall ensure that the programs and activities specified as necessary in the BWRVIP-74 report are summarily described in the FSAR supplement.	The FSAR supplement, contained in Appendix A of the LRA, includes a summary description of the programs and activities as required by this Applicant Action Item.

Table C-11

BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
(3) 10 CFR 54.22 requires that each LR application include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the LR application. In its Appendix A to the BWRVIP-74 report, the BWRVIP stated that the technical specification changes resulting from neutron embrittlement will be made at the appropriate time prior to the end of the current license. Those LR applicants referencing the BWRVIP-74 report for the RPV components shall ensure that the inspection strategy described in the BWRVIP-74 report does not conflict or result in any changes to their technical specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its LR application.	No technical specification changes are required for the inspection strategy described in the BWRVIP-74-A report. Technical specification changes due to embrittlement, i.e. Pressure-Temperature Limits, will be submitted prior to the expiration of the currently approved limits, as discussed in LRA Section 4.2.
(4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The reactor vessel flange leak detection (VFLD) lines are in the scope of license renewal. See the scoping and screening results in the LRA for the Reactor Coolant System Pressure Boundary (piping and fittings, flange leak detection lines, Section 2.3.1.3 and Table 3.1.2-3). Refer to Section 3.1.2.2.4 of the LRA for further information, and also see item 3.1.1-19 in LRA Table 3.1.1. Cracking of these lines is managed by the Small Bore Class 1 Piping Inspection. This aging management program is described in Appendix B of the LRA.

Table C-11

BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
(5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	A description of the aging management programs credited for license renewal is provided in Appendix B of the LRA. These descriptions include a comparison of each program element to the 10 elements in the NUREG-1801 program for plant-specific programs.
(6) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applications shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29.	As described in Appendix B of the LRA, Columbia has an existing BWR Water Chemistry Program as a preventative measure against cracking due to stress corrosion cracking and intergranular attack. As discussed in Appendix B of the LRA, the BWR Water Chemistry Program is consistent with NUREG-1801 section XI.M2. The BWR Water Chemistry Program is based periodically updated to the latest EPRI BWR water chemistry guidelines (currently BWRVIP-130).
(7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific in-vessel surveillance program, applicable to the LR term.	As described in Appendix B of the LRA, the Reactor Vessel Surveillance Program is part of the ISP, described in BWRVIP-86-A and BWRVIP-116, and approved by the NRC staff.
(8) LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.	Metal fatigue (including discussion of cycles, projected cumulative usage factors, and environmental fatigue effects) is addressed in Section 4.3 of the LRA.

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BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
(9) Appendix A to the BWRVIP-74 report indicates that a set of P-T curves should be developed for the heatup and cooldown operating conditions in the plant at a given EFPY in the LR period.	The Columbia pressure-temperature (P-T) limit curves were revised in 2005 to include the effects of power uprate and are valid for 33.1 EFPY. The P-T limits will be revised when necessary to comply with 10 CFR 50 Appendix G, as discussed in Section 4.2.4 of the LRA.
(10) To demonstrate that the beltline materials meet the Charpy USE criteria in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.	The Columbia beltline materials meet the criteria in Appendix B of BWRVIP-74. Details of the Charpy upper shelf energy (USE) evaluation for the reactor vessel beltline materials are provided in Section 4.2.2 of the LRA.
(11) To obtain relief from the inservice inspection of the circumferential welds during the LR period, the BWRVIP report indicates that each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E of the staff's July 28, 1998, FSER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	(1) The Columbia circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in Appendix E of the staff's July 28, 1998, FSER. Details are presented in Section 4.2.5 of the LRA. (2) Columbia has implemented operator training and established procedures that limit the frequency of cold overpressure events. The details were presented in Columbia's original request for relief. The NRC approval of that request (see Reference 4.8-9 in LRA Section 4.8) agreed that Columbia has implemented the necessary operator training and procedural controls.

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BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
(12) As indicated in the staff's March 7, 2000 letter to Carl Terry, a LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine the mean RT_{NDT} of the limiting axial beltline weld at the end of the extended period of operation is less than the values specified in Table 1 of this FSER.	The projected RT_{NDT} of Columbia's limiting axial beltline weld at the end of the extended period of operation is less than the values specified in Table 1 of the FSER for BWRVIP-74. Details of the evaluation are in Section 4.2.6 of the LRA.
(13) The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using a staff approved methodology or may submit the methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.	Columbia used fluence methodology that was approved by the NRC based on the methodology following the guidance in Regulatory Guide (RG) 1.190. See Section 4.2.1 of the LRA.
(14) Components that have indications that have been previously analytically evaluated in accordance with Subsection IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be re-evaluated for the 60 year service period corresponding to the LR term.	Columbia has two indications that have been previously evaluated (one analysis) in accordance with Subsection IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period. These two reactor vessel shell indications were evaluated for the period of extended operation and cracking of these indications will be managed by the Inservice Inspection (ISI) Program. Details of the evaluation are in Section 4.7.1 of the LRA.

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BWRVIP-116 BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
BWR licensees who wish to participate in the ISP(E) must complete the ISP(E) implementation as follows, based on the status of its license renewal application: (c) BWR licensees that will submit a license renewal application shall implement the ISP(E) by revising their licensing basis to include the approved version of BWRVIP-116 in its application and the proposed licensing basis for the extended period of operation.	As discussed in the Reactor Vessel Surveillance Program, Columbia has implemented the ISP as approved by the NRC staff. Energy Northwest will submit a licensing basis change request to implement the BWRVIP ISP(E) at least two years prior to the period of extended operation.
In addition to the information in the BWRVIP's letter dated January 11, 2005, which amends BWRVIP-116, the BWRVIP shall include in the approved version of BWRVIP-116, the following concerning the withdrawal schedule and contingency plans as discussed in this SE. a. NRC staff notes that the new capsule test schedule in Table 1 of the BWRVIP letter dated January 11, 2005, should replace Table 2-2 of BWRVIP-116.	Energy Northwest will submit a licensing basis change request to implement the BWRVIP ISP(E) at least two years prior to the period of extended operation. Columbia will implement the ISP(E) as amended by the BWRVIP letter of January 11, 2005, including the new capsule test schedule in Table 1 of that letter.

Table C-12

BWRVIP-116 BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
b. The BWRVIP-116 report should include the necessary information to ensure the contingency plan continues to meet the criterion in Paragraph III.C.d of Appendix H to 10 CFR Part 50. This information should ensure: (1) All surveillance material with unirradiated CVN baseline data, which includes tested/broken CVN specimens and partially and/or untested surveillance capsule material, must be kept in a condition to allow for possible future testing. (2) If these surveillance material are removed from the RPV, without the intent to test them, these capsules must be stored in a manner which maintains them in a condition which would support possible re-insertion into an RPV, if necessary under the contingency plan. (3) Prior to any changes to the storage of these materials, the BWRVIP must be notified to determine whether these changes are acceptable. The BWRVIP must obtain NRC approval for any changes that would prevent the possible testing of these surveillance materials under the contingency plan.	Implementation of the BWRVIP ISP(E) for Columbia will include the following details in support of the contingency plan: (1) Energy Northwest will include the requirement to keep all tested material (irradiated or unirradiated) for possible future reconstitution and testing. (2) The Columbia site procedure has been modified to require any capsules removed from the reactor vessel to be stored in a manner that would support future re-insertion of these capsules in the reactor vessel. (3) Energy Northwest will notify the BWRVIP prior to any change in the storage of on-site materials. NRC approval will be obtained prior to any change in the storage of surveillance materials that would affect the potential use of the materials under the contingency plan. See the Reactor Vessel Surveillance Program for more details.

Table C-12

BWRVIP-116 BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal	
Applicant Action Item Text	**Plant-Specific Response**
Finally, if a BWR facility proposes to change its neutron fluence determination methodology, the facility must request approval from the NRC staff to determine its acceptability, determine whether the neutron fluence determination methodologies are compatible for use in the ISP(E) and determine if the methodologies have been or will be benchmarked against existing dosimetry data bases. The information submitted to the NRC staff must be sufficient for the staff to determine that: (1) RPV and surveillance capsule fluences will be established as based on the use of an NRC-approved fluence methodology that will provide acceptable results based on the available dosimetry data, and (2) if one methodology is used to determine the neutron fluence values for a licensee's RPV and one or more different methodologies are used to establish the neutron fluence values for the ISP(E) surveillance capsules which "represent" that RPV in the ISP, the results of these differing methodologies are compatible (i.e., within acceptable levels of uncertainty for each calculation).	Columbia does not propose to change its neutron fluence determination methodology. Neutron fluence methodology is discussed in LRA Section 4.2.

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APPENDIX D

TECHNICAL SPECIFICATION CHANGES

10 CFR 54.22 requires that an application for license renewal include any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation.

No changes to the Columbia Technical Specifications are required to support the License Renewal Application.

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