F4. DIESEL GENERATOR BUILDING VENTILATION SYSTEM

F4.1 Duct

F4.1.1 Duct Fittings, Access Doors, and Closure Bolts
F4.1.2 Equipment Frames and Housing
F4.1.3 Flexible Collars between Ducts and Fans
F4.1.4 Seals in Dampers and Doors

F4.2 Air Handler Heating/Cooling

F4.2.1 Heating/Cooling Coils

F4.3 Piping

F4.3.1 Piping and Fittings

F4. DIESEL GENERATOR BUILDING VENTILATION SYSTEM

Systems, Structures, and Components

This section comprises the diesel generator building ventilation system (with warm moist air as the normal environment), which contains ducts, piping and fittings, equipment frames and housings, flexible collars and seals, and heating and cooling air handlers. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the diesel generator building ventilation system are governed by Group C Quality Standards.

With respect to seals, these items are to be addressed consistent with the NRC position on consumables, provided in the NRC letter from Christopher I. Grimes to Douglas J. Walters of NEI, dated March 10, 2000. Specifically, components that function as system seals are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from an aging management review under 10 CFR 54.21(a)(1)(ii). The application is to identify the standards that are relied on for replacement as part of the methodology description, for example, NFPA standards for fire protection equipment.

Aging management programs for the degradation of external surfaces of carbon steel components are included in VII.I.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The system that interfaces with the diesel generator building system is the auxiliary and radwaste area ventilation system (VII.F2). The cooling coils receive their cooling water from other systems, such as the hot water heating system or the chilled water cooling system.

VII Auxiliary Systems
F4. Diesel Generator Building Ventilation System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
F4.1-a F4.1.1 F4.1.2	Duct Duct fittings, access doors, and closure bolts Equipment frames and housing	Carbon steel (galvanized or painted); Bolts: plated carbon steel	Warm, moist air	Loss of material/ General, pitting, crevice corrosion, and microbiologically influenced corrosion (for duct [drip-pan] and piping for moisture drainage)	A plant-specific aging management program is to be evaluated.	Yes, plant specific
F4.1-b F4.1.3 F4.1.4	Duct Flexible collars between ducts and fans Seals in dampers and doors	Elastomer (Neoprene)	Warm, moist air	Hardening and loss of strength/ Elastomer degradation	A plant-specific aging management program is to be evaluated.	Yes, plant specific
F4.1-c F4.1.3 F4.1.4	Duct Flexible collars between ducts and fans Seals in dampers and doors	Elastomer (Neoprene)	Warm, moist air	Loss of material/ Wear	A plant-specific aging management program is to be evaluated.	Yes, plant specific
F4.2-a F4.2.1	Air handler heating/cooling Heating/cooling coils	Copper/nickel	Warm, moist air	Loss of material/ Pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
F4.3-a F4.3.1	Piping Piping and fittings	Carbon steel	Hot or cold treated water	Loss of material/ General, pitting and crevice corrosion	Chapter XI.M21, "Closed-Cycle Cooling Water System"	No

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G. FIRE PROTECTION

G.1 Intake Structure

G.1.1 Fire Barrier Penetration Seals
G.1.2 Fire Barrier Walls, Ceilings, and Floors
G.1.3 Fire Rated Doors

G.2 Turbine Building

G.2.1 Fire Barrier Penetration Seals
G.2.2 Fire Barrier Walls, Ceilings, and Floors
G.2.3 Fire Rated Doors

G.3 Auxiliary Building

G.3.1 Fire Barrier Penetration Seals
G.3.2 Fire Barrier Walls, Ceilings, and Floors
G.3.3 Fire Rated Doors

G.4 Diesel Generator Building

G.4.1 Fire Barrier Penetration Seals
G.4.2 Fire Barrier Walls, Ceilings, and Floors
G.4.3 Fire Rated Doors

G.5 Primary Containment

G.5.1 Fire Barrier Walls, Ceilings, and Floors
G.5.2 Fire Rated Doors

G.6 Water-Based Fire Protection System

G.6.1 Piping and Fittings
G.6.2 Filter, Fire Hydrants, Mulsifier, Pump Casing, Sprinkler, Strainer, and Valve Bodies (including containment isolation valves)

G.7 Reactor Coolant Pump Oil Collection System

G.7.1 Tank
G.7.2 Piping, Tubing, and Valve Bodies

G.8 Diesel Fire System

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

G. FIRE PROTECTION

Systems, Structures, and Components

This section comprises the fire protection systems for both boiling water reactors (BWRs) and pressurized water reactors (PWRs), which consist of several Class 1 structures, mechanical systems, and electrical components. The Class 1 structures include the intake structure, the turbine building, the auxiliary building, the diesel generator building, and the primary containment. Structural components include fire barrier walls, ceilings, floors, fire doors, and penetration seals. Mechanical systems include the high pressure service water system, the reactor coolant pump oil collect system, and the diesel fire system. Mechanical components include piping and fittings, filters, fire hydrants, mulsifiers, pumps, sprinklers, strainers, and valves (including containment isolation valves). Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all of the mechanical components are governed by Group C Quality Standards.

With respect to filters, seals, portable fire extinguishers, and fire hoses, these items are to be addressed consistent with the NRC position on consumables, provided in the NRC letter from Christopher I. Grimes to Douglas J. Walters of NEI, dated March 10, 2000. Specifically, components that function as system filters, seals, portable fire extinguishers, and fire hoses are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from an aging management review under 10 CFR 54.21(a)(1)(ii). The application is to identify the standards that are relied on for replacement as part of the methodology description, for example, NFPA standards for fire protection equipment.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or are subject to replacement based on qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of external surfaces of carbon steel components are included in VII.I.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems and structures that interface with the fire protection system include various Class 1 structures and component supports (III.A and III.B), the electrical components (VI.A and VI.B), the closed-cycle cooling water system (VII.C2), and the diesel fuel oil system (VII.H1).

VII **Auxiliary Systems**
G. Fire Protection

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.1-a G.1.1	Intake structure Fire barrier penetration seals (for piping, electrical conduit, cable tray, heating, ventilation, air condition, and expansion joint)	Sealant	Indoors: air; outdoors: sun, weather, humidity, and moisture	Increased hardness and shrinkage/ Weathering	Chapter XI.M26, "Fire Protection"	No
G.1-b G.1.2	Intake structure Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Concrete cracking and spalling/ Freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection" and Chapter XI.S6, "Structures Monitoring Program"	No
G.1-c G.1.2	Intake structure Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Loss of material/ Corrosion of embedded steel	Chapter XI.M26, "Fire Protection" and Chapter XI.S6, "Structures Monitoring Program"	No
G.1-d G.1.3	Intake structure Fire rated doors	Steel	Indoor and outdoor environments	Loss of material/ Wear	Chapter XI.M26, "Fire Protection"	No
G.2-a G.2.1	Turbine building Fire barrier penetration seals (for piping, electrical conduit, cable tray, heating, ventilation, air condition, and expansion joint)	Sealant	Indoors: air; outdoors: sun, weather, humidity, and moisture	Increased hardness and shrinkage/ Weathering	Chapter XI.M26, "Fire Protection"	No
G.2-b G.2.2	Turbine building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Concrete cracking and spalling/ Freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection" and Chapter XI.S6, "Structures Monitoring Program"	No
G.2-c G.2.2	Turbine building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Loss of material/ Corrosion of embedded steel	Chapter XI.M26, "Fire Protection" and Chapter XI.S6, "Structures Monitoring Program"	No

VII Auxiliary Systems
G. Fire Protection

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.2-d G.2.3	Turbine building Fire rated doors	Steel	Indoor and outdoor environments	Loss of material/ Wear	Chapter XI.M26, "Fire Protection"	No
G.3-a G.3.1	Auxiliary building Fire barrier penetration seals (for piping, electrical conduit, cable tray, heating, ventilation, air condition, and expansion joint)	Sealant	Indoors: air; outdoors: sun, weather, humidity, and moisture	Increased hardness and shrinkage/ Weathering	Chapter XI.M26, "Fire Protection"	No
G.3-b G.3.2	Auxiliary building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Concrete cracking and spalling/ Freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No
G.3-c G.3.2	Auxiliary building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Loss of material/ Corrosion of embedded steel	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No
G.3-d G.3.3	Auxiliary building Fire rated doors	Steel	Indoor and outdoor environments	Loss of material/ Wear	Chapter XI.M26, "Fire Protection"	No
G.4-a G.4.1	Diesel generator building Fire barrier penetration seals (for piping, electrical conduit, cable tray, heating, ventilation, air condition, and expansion joint)	Sealant	Indoors: air; outdoors: sun, weather, humidity, and moisture	Increased hardness and shrinkage/ Weathering	Chapter XI.M26, "Fire Protection"	No
G.4-b G.4.2	Diesel generator building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Concrete cracking and spalling/ Freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No

VII Auxiliary Systems
G. Fire Protection

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.4-c G.4.2	Diesel generator building Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor and outdoor environments	Loss of material/ Corrosion of embedded steel	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No
G.4-d G.4.3	Diesel generator building Fire rated doors	Steel	Indoor and outdoor environments	Loss of material/ Wear	Chapter XI.M26, "Fire Protection"	No
G.5-a G.5.1	Primary containment Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor	Concrete cracking and spalling/ Aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No
G.5-b G.5.1	Primary containment Fire barrier walls, ceilings, and floors	Concrete and reinforcement	Indoor	Loss of material/ Corrosion of embedded steel	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring Program"	No
G.5-c G.5.2	Primary containment Fire rated doors	Steel	Indoor	Loss of material/ Wear	Chapter XI.M26, "Fire Protection"	No
G.6-a G.6.1	Water-based fire protection system Piping and fittings	Carbon steel, cast iron, and stainless steel	Raw water	Loss of material/ General, galvanic, pitting, crevice, microbiologically influenced corrosion and biofouling	Chapter XI.M27, "Fire Water System"	No
G.6-b G.6.2	Water-based fire protection system Filter, fire hydrant, mulsifier, pump casing, sprinkler, strainer, and valve bodies (including containment isolation valves)	Carbon steel, cast iron, bronze, copper, stainless steel	Raw water	Loss of material/ General, galvanic, pitting, crevice, microbiologically influenced corrosion and biofouling	Chapter XI.M27, "Fire Water System"	No

VII Auxiliary Systems
G. Fire Protection

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.7-a G.7.1	Reactor coolant pump oil collection system Tank	Carbon steel	Lubricating oil (with contaminants and/or moisture)	Loss of material/ General, galvanic, pitting and crevice corrosion	A plant specific aging management program that determines the thickness of the lower portion of the tank is to be evaluated. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.7-b G.7.2	Reactor coolant pump oil collection system Piping, tubing, valve bodies	Piping and valve bodies: carbon steel; tubing: copper, brass	Lubricating oil (with contaminants and/or moisture)	Loss of material/ General, galvanic, pitting and crevice corrosion	A plant specific aging management program that monitors the degradation of the components is to be evaluated. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.8-a G.8.1	Diesel fire system Diesel-driven fire pump (pump casing) and fuel oil supply line	Carbon steel	Fuel oil	Loss of material/ General, galvanic, pitting and crevice corrosion	Chapter XI.M26, "Fire Protection," and Chapter XI.M30, "Fuel Oil Chemistry"	No

H1. DIESEL FUEL OIL SYSTEM

H1.1 Piping

H1.1.1 Aboveground Pipe and Fittings
H1.1.2 Underground Pipe and Fittings

H1.2 Valves

H1.2.1 Body and Bonnet
H1.2.2 Closure Bolting

H1.3 Pump

H1.3.1 Casing
H1.3.2 Closure Bolting

H1.4 Tank

H1.4.1 Internal Surface
H1.4.2 External Surface

H1. DIESEL FUEL OIL SYSTEM

Systems, Structures, and Components

This section comprise the diesel fuel oil system, which consists of aboveground and underground piping, valves, pumps, and tanks. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the diesel fuel oil system are governed by Group C Quality Standards.

Aging management programs for the degradation of external surfaces of carbon steel components are included in VII.I.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the diesel fuel oil system are the fire protection (VII.G) and emergency diesel generator systems (VII.H2).

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
H1.1-a H1.1.1	Piping Aboveground piping and fittings	Carbon steel	Outdoor ambient conditions	Loss of material/ General, pitting, and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H1.1-b H1.1.2	Piping Underground piping and fittings	Carbon steel	Soil and groundwater	Loss of material/ General, galvanic, pitting, crevice and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes, detection of aging effects and operating experience are to be further evaluated
H1.2-a H1.2.1 H1.2.2	Valves Body and bonnet Closure bolting	Carbon steel or low-alloy steel	Outdoor ambient conditions	Loss of material/ General, pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H1.3-a H1.3.1 H1.3.2	Pump Casing Closure bolting	Carbon steel or low-alloy steel	Outdoor ambient conditions	Loss of material/ General, pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H1.4-a H1.4.1	Tank Internal surface	Carbon steel	Fuel oil, water (as contaminant)	Loss of material/ General, pitting, crevice, microbiologically influenced corrosion and biofouling	Chapter XI.M30, "Fuel Oil Chemistry" The AMP is to be augmented by verifying the effectiveness of fuel oil chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
H1.4-b H1.4.2	Tank External surface	Carbon steel	Outdoor ambient conditions	Loss of material/ General, pitting and crevice corrosion	Chapter XI.M29, "Aboveground Carbon Steel Tanks"	No

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H2. EMERGENCY DIESEL GENERATOR SYSTEM

H2.1 Diesel Engine Cooling Water Subsystem

H2.1.1 Pipe and Fittings

H2.2 Diesel Engine Starting Air Subsystem

H2.2.1 Pipe and Fittings
H2.2.2 Valves (Hand and Check)
H2.2.3 Drain Trap
H2.2.4 Air Accumulator Vessel

H2.3 Diesel Engine Combustion Air Intake Subsystem

H2.3.1 Piping and Fittings
H2.3.2 Filter
H2.3.3 Muffler

H2.4 Diesel Engine Combustion Air Exhaust Subsystem

H2.4.1 Piping and Fittings
H2.4.2 Muffler

H2.5 Diesel Engine Fuel Oil Subsystem

H2.5.1 Tanks (Day and Drip)

H2. EMERGENCY DIESEL GENERATOR SYSTEM

Systems, Structures, and Components

This section comprises the emergency diesel generator system, which contains piping, valves, filters, mufflers, strainers, and tanks. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the emergency diesel generator system are governed by Group C Quality Standards.

With respect to filters, these items are to be addressed consistent with the NRC position on consumables, provided in the NRC letter from Christopher I. Grimes to Douglas J. Walters of NEI, dated March 10, 2000. Specifically, components that function as system filters are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from an aging management review under 10 CFR 54.21(a)(1)(ii). The application is to identify the standards that are relied on for replacement as part of the methodology description, for example, NFPA standards for fire protection equipment.

Aging management programs for the degradation of external surfaces of carbon steel components are included in VII.I.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the emergency diesel generator system include the diesel fuel oil system (VII.H1), the closed-cycle cooling water system (VII.C2) and, for some plants, the open-cycle cooling water system (VII.C1).

VII Auxiliary Systems
H2. Emergency Diesel Generator System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
H2.1-a H2.1.1	Diesel engine cooling water subsystem (serviced by closed-cycle cooling water system) Piping and fittings	Carbon steel	Chemically treated demineralized water <90°C (194°F)	Loss of Material/ General, pitting and crevice corrosion	Chapter XI.M21, "Closed-Cycle Cooling Water System"	No
H2.1-b H2.1.1	Diesel engine cooling water subsystem (serviced by open-cycle cooling water system) Piping and fittings	Carbon steel	Raw, untreated salt water or fresh water	Loss of Material/ General, pitting, crevice, microbiologically influenced corrosion and biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
H2.2-a H2.2.1 H2.2.2 H2.2.3 H2.2.4	Diesel engine starting air subsystem Piping and fittings Valves (hand and check) Drain trap Air accumulator vessel	Carbon steel	Moist air	Loss of material/ General, pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H2.3-a H2.3.1 H2.3.2 H2.3.3	Diesel engine combustion air intake subsystem Piping and fittings Filter Muffler	Carbon steel	Moist air	Loss of material/ General, pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H2.4-a H2.4.1 H2.4.2	Diesel engine combustion air exhaust subsystem Piping and fittings Muffler	Carbon steel	Hot diesel engine exhaust gases containing moisture and particulates	Loss of material/ General, pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific

VII Auxiliary Systems
H2. Emergency Diesel Generator System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
H2.5-a H2.5.1	Diesel engine fuel oil subsystem Tanks (day and drip)	Carbon steel	Diesel fuel oil	Loss of Material/ General, pitting, crevice and microbiologically influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry" The AMP is to be augmented by verifying the effectiveness of fuel oil chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

I. CARBON STEEL COMPONENTS

I.1 Carbon Steel Components

I.1.1 External Surfaces

I.2 Closure Bolting

I.2.1 In High-Pressure or High-Temperature Systems

I. CARBON STEEL COMPONENTS

Systems, Structures, and Components

This section includes the aging management programs for the external surfaces of all carbon steel structures and components including closure boltings in the Auxiliary Systems in pressurized water reactors (PWRs) and boiling water reactors (BWRs). For the carbon steel components in PWRs, this section addresses only boric acid corrosion of external surface as a result of the dripping borated water that is leaking from an adjacent PWR component. Boric acid corrosion can also occur for carbon steel components containing borated water due to leakage; such components and the related aging management program are covered in the appropriate major plant sections in VII.

System Interfaces

The structures and components covered in this section belong to the Auxiliary Systems in PWRs and BWRs. (For example, see System Interfaces in VII.A1 to VII.H2 for details.)

VII Auxiliary Systems

I. Carbon Steel Components

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
I.1-a I.1.1	Carbon steel components (PWRs) External surfaces	Carbon steel, low-alloy steel	Air, leaking and dripping chemically treated borated water up to 340°C (644°F)	Loss of material/ Boric acid corrosion of external surfaces	Chapter XI.M10, "Boric Acid Corrosion"	No
I.1-b I.1.1	Carbon steel components (PWRs and BWRs) External surfaces	Carbon steel, low-alloy steel	Air, moisture, and humidity < 100°C (212°F)	Loss of material/ General corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
I.2-a I.2.1	Closure bolting In high-pressure or high-temperature systems	Carbon steel, low-alloy steel	Air, moisture, humidity, and leaking fluid	Loss of material/ General corrosion	Chapter XI.M18, "Bolting Integrity"	No
I.2-b I.2.1	Closure bolting In high-pressure or high-temperature systems	Carbon steel, low-alloy steel	Air, moisture, humidity, and leaking fluid	Crack initiation and growth/ Cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No

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CHAPTER VIII

STEAM AND POWER CONVERSION SYSTEM

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MAJOR PLANT SECTIONS

A. Steam Turbine System

B1. Main Steam System (PWR)

B2. Main Steam System (BWR)

C. Extraction Steam System

D1. Feedwater System (PWR)

D2. Feedwater System (BWR)

E. Condensate System

F. Steam Generator Blowdown System (PWR)

G. Auxiliary Feedwater (AFW) System (PWR)

H. Carbon Steel Components

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A. STEAM TURBINE SYSTEM

A.1 Piping and Fittings

A.1.1 High Pressure (HP) Turbine to Moisture Separator/Reheater (MSR)
A.1.2 MSR to Low Pressure (LP) Turbine

A.2 Valves (Stop, Control or Governor, Intermediate Stop and Control or Combined Intermediate, Bypass or Steam Dumps, Atmospheric Dumps, Main Steam Safety, or Safety/Relief)

A.2.1 Body and Bonnet

A. STEAM TURBINE SYSTEM

Systems, Structures, and Components

This section comprises the piping and fittings in the steam turbine system for both pressurized water reactors (PWRs) and boiling water reactors (BWRs) and consists of the lines from the high-pressure (HP) turbine to the moisture separator/reheater (MSR) and the lines from the MSR to the low-pressure (LP) turbine. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the steam turbine system are governed by Group D Quality Standards.

The steam turbine performs its intended functions with moving parts and does not require an aging management review under 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the steam turbine system include the main steam system (VIII.B1 and VIII.B2), the extraction steam system (VIII.C), and the condensate system (VIII.E).

VIII Steam and Power Conversion System
A. Steam Turbine System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
A.1-a A.1.1 A.1.2	Piping and fittings HP turbine to MSR MSR to LP turbine	Carbon steel	Steam	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
A.1-b A.1.1 A.1.2	Piping and fittings HP turbine to MSR MSR to LP turbine	Carbon steel	Steam	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
A.2-a A.2.1	Valves (stop, control or governor, intermediate stop and control or combined intermediate, bypass or steam dumps, atmospheric dumps, main steam safety, or safety/relief) Body and bonnet	Carbon steel	Steam	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
A.2-b A.2.1	Valves (stop, control or governor, intermediate stop and control or combined intermediate, bypass or steam dumps, atmospheric dumps, main steam safety, or safety/relief) Body and bonnet	Carbon steel	Steam	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

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B1. MAIN STEAM SYSTEM (PWR)

B1.1 Piping and Fittings

B1.1.1 Steam Lines from Steam Generator to Isolation Valves (Group B or C)
B1.1.2 Steam Lines from Isolation Valves to Main Turbine (Group D)
B1.1.3 Lines to Feedwater (FW) and Auxiliary Feedwater (AFW) Pump Turbines
B1.1.4 Lines to Moisture Separator/Reheater (MSR)
B1.1.5 Turbine Bypass
B1.1.6 Steam Drains

B1.2 Valves (Check, Control, Hand, Motor Operated, Safety, and Containment Isolation Valves)

B1.2.1 Body and Bonnet

B1 MAIN STEAM SYSTEM (PWR)

Systems, Structures, and Components

This section comprises the main steam system for pressurized water reactors (PWRs). The section includes the main steam lines from the steam generator to the steam turbine and the turbine bypass lines from the main steam lines to the condenser. Also included are the lines to the main feedwater (FW) and auxiliary feedwater (AFW) pump turbines, steam drains, and valves, including the containment isolation valves on the main steam lines and lines to the AFW pump turbines.

Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," the portion of the main steam system extending from the steam generator up to the second containment isolation valve is governed by Group B or C Quality Standards, and all other components that comprise the main steam system located downstream of the isolation valves are governed by Group D Quality Standards.

The internals of the valves perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems and structures that interface with the main steam system include PWR concrete or steel containment structures (II.A1 and II.A2), common components (II.A3), the steam generator (IV.D1 and IV.D2), the steam turbine system (VIII.A), the feedwater system (VIII.D1), the condensate system (VIII.E), and the auxiliary feedwater system (VIII.G).

VIII Steam Power Conversion System
B1. Main Steam System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
B1.1-a B1.1.1 B1.1.2	Piping and fittings Steam lines from steam generator to isolation valves (Group B or C) Steam lines from isolation valves to main turbine (Group D)	Carbon steel	Up to 300°C (572°F) steam	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134	No
B1.1-b B1.1.1	Piping and fittings Steam lines from steam generator to isolation valves (Group B or C)	Carbon steel	Up to 300°C (572°F) steam	Cumulative fatigue damage/ Fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.3, "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c).	Yes, TLAA
B1.1-c B1.1.1 B1.1.2 B1.1.3 B1.1.4 B1.1.5 B1.1.6	Piping and fittings Steam lines from steam generator to isolation valves (Group B or C) Steam lines from isolation valves to main turbine (Group D) Lines to FW and AFW pump turbines Lines to MSR Turbine bypass Steam drains	Carbon steel	Up to 300°C (572°F) steam	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
B1.2-a B1.2.1	Valves (check, control, hand, motor operated, safety, and containment isolation valves) Body and bonnet	Carbon steel	Up to 300°C (572°F) steam	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134	No
B1.2-b B1.2.1	Valves (check, control, hand, motor operated, safety, and containment isolation valves) Body and bonnet	Carbon steel	Up to 300°C (572°F) steam	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No

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B2 MAIN STEAM SYSTEM (BWR)

B2.1 Piping and Fittings

B2.1.1 Steam Lines to Main Turbine (Group B)
B2.1.2 Steam Lines to Main Turbine (Group D)
B2.1.3 Lines to FW Pump Turbines
B2.1.4 Turbine Bypass
B2.1.5 Steam Drains
B2.1.6 Steam Line to HPCI Turbine
B2.1.7 Steam Line to RCIC Turbine

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

B2.2.1 Body and Bonnet

B2. MAIN STEAM SYSTEM (BWR)

Systems, Structures, and Components

This section comprises the main steam system for boiling water reactors (BWRs). The section includes the main steam lines from the outermost containment isolation valve to the steam turbines and the turbine bypass lines from the main steam lines to the condenser. Also included are steam drains, and lines to main feedwater (FW), high-pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) turbines.

Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," portions of the main steam system extending from the outermost containment isolation valve up to and including the turbine stop and bypass valves, as well as connected piping up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation, are governed by Group B Quality Standards. The remaining portions of the main steam system consist of components governed by the Group D Quality Standards. For BWRs containing a shutoff valve in addition to the two containment isolation valves in the main steam line, Group B Quality Standards are applied only to those portions of the system extending from the outermost containment isolation valves up to and including the shutoff valve. The portion of the main steam system extending from the reactor pressure vessel up to the second isolation valve and including the containment isolation valves is governed by Group A Quality Standards and is covered in IV.C1.

The valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the main steam system include the BWR Mark 1, Mark 2, or Mark 3 containment structures (II.B1, II.B2, and II.B3, respectively) and common components (II.B4), the reactor coolant pressure boundary (IV.C1), the steam turbine system (VIII.A), the feedwater system (VIII.D2), and the condensate system (VIII.E).

VIII Steam Power Conversion System
B2. Main Steam System (BWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
B2.1-a B2.1.1 B2.1.2	Piping and fittings Steam lines to main turbine (Group B) Steam lines to main turbine (Group D)	Carbon steel	288°C (550°F) steam	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515)	No
B2.1-b B2.1.1 B2.1.2 B2.1.3 B2.1.4 B2.1.5 B2.1.6 B2.1.7	Piping and fittings Steam lines to main turbine (Group B) Steam lines to main turbine (Group D) Lines to FW pump turbines Turbine bypass Steam drains Steam line to HPCI turbine Steam line to RCIC turbine	Carbon steel	288°C (550°F) steam	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
B2.1-c B2.1.1 B2.1.2 B2.1.3 B2.1.4 B2.1.5 B2.1.6 B2.1.7	Piping and fittings Steam lines to main turbine (Group B) Steam lines to main turbine (Group D) Lines to FW pump turbines Turbine bypass Steam drains Steam line to HPCI turbine Steam line to RCIC turbine	Carbon steel	288°C (550°F) steam	Cumulative fatigue damage/ Fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.3, "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c).	Yes, TLAA
B2.2-a B2.2.1	Valves (check, control, hand, motor operated, safety valves) Body and bonnet	Carbon steel	288°C (550°F) steam	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
B2.2-b B2.2.1	Valves (check, control, hand, motor operated, safety valves) Body and bonnet	Carbon steel	288°C (550°F) steam	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515)	No

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C. EXTRACTION STEAM SYSTEM

C.1 Piping and Fittings

C.1.1 Lines to Feedwater Heaters
C.1.2 Steam Drains

C.2 Valves

C.2.1 Body and Bonnet

C. EXTRACTION STEAM SYSTEM

Systems, Structures, and Components

This section comprises the extraction steam lines for both pressurized water reactors (PWRs) and boiling water reactors (BWRs), which extend from the steam turbine to the feedwater heaters, including the drain lines. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the extraction steam system are governed by Group D Quality Standards.

The internals of the valves perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the extraction steam system include the steam turbine system (VIII.A), the feedwater system (VIII.D1 and VIII.D2), and the condensate system (VIII.E).

VIII Steam Power Conversion System
C. Extraction Stream System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
C.1-a C.1.1 C.1.2	Piping and fittings Lines to feedwater heaters Steam drains	Carbon steel	Up to 300°C (572°F) steam	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
C.1-b C.1.1 C.1.2	Piping and fittings Lines to feedwater heaters Steam drains	Carbon steel	Up to 300°C (572°F) steam	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
C.2-a C.2.1	Valves Body and bonnet	Carbon steel	Up to 300°C (572°F) steam	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
C.2-b C.2.1	Valves Body and bonnet	Carbon steel	Up to 300°C (572°F) steam	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

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D1. FEEDWATER SYSTEM (PWR)

D1.1 Main Feedwater Line

D1.1.1 Pipe and Fittings (Group B, C, or D)

D1.2 Valves (Control, Check, Hand, Safety, and Containment Isolation Valves)

D1.2.1 Body and Bonnet

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

D1.3.1 Casing
D1.3.2 Suction and Discharge Lines

D1. FEEDWATER SYSTEM (PWR)

Systems, Structures, and Components

This section comprises the main feedwater system for pressurized water reactors (PWRs), which extends from the condensate system to the steam generator. They consist of the main feedwater lines, feedwater pumps, and valves, including the containment isolation valves. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," the portion of the feedwater system extending from the secondary side of the steam generator up to the second containment isolation valve is governed by Group B or C Quality Standards, and all other components in the feedwater system located downstream from the isolation valves are governed by Group D Quality Standards.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems and structures that interface with the feedwater system include PWR concrete or steel containment structures (II.A1 and II.A2) and common components (II.A3), the steam generators (IV.D1 and IV.D2), the main steam system (VIII.B1), the extraction steam system (VIII.C), the condensate system (VIII.E), and the auxiliary feedwater system (VIII.G).

VIII Steam and Power Conversion System
D1. Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
D1.1-a D1.1.1	Main feedwater line Piping and fittings (Group B, C, or D)	Carbon steel	Treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
D1.1-b D1.1.1	Main feedwater line Piping and fittings (Group B or C from steam generator to isolation valves)	Carbon steel	Treated water	Cumulative fatigue damage/ Fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.3, "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c).	Yes, TLAA
D1.1-c D1.1.1	Main feedwater line Piping and fittings (Group B, C, or D)	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
D1.2-a D1.2.1	Valves (control, check, hand, safety, and containment isolation valves) Body and bonnet	Carbon steel	Treated water	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
D1.2-b D1.2.1	Valves (control, check, and hand, safety, and containment isolation valves) Body and bonnet	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VIII Steam and Power Conversion System
D1. Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
D1.3-a D1.3.1 D1.3.2	Feedwater pump (steam turbine and motor driven) Casing Suction and discharge lines	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
D1.3-b D1.3.2	Feedwater pump (steam turbine and motor driven) Suction and discharge lines	Carbon steel	Treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No

D2. FEEDWATER SYSTEM (BWR)

D2.1 Main Feedwater Line

D2.1.1 Pipe and Fittings (Group B or D)

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

D2.2.1 Body and Bonnet

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

D2.3.1 Casing
D2.3.2 Suction and Discharge Lines

D2. FEEDWATER SYSTEM (BWR)

Systems, Structures, and Components

This section comprises the main feedwater system for boiling water reactors (BWRs), which extends from the condensate and condensate booster system to the outermost feedwater isolation valve on the feedwater lines to the reactor vessel. They consist of the main feedwater lines, feedwater pumps, and valves.

Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," the portions of the feedwater system extending from the outermost containment isolation valves up to and including the shutoff valve or the first valve that is either normally closed or capable of closure during all modes of normal reactor operation are governed by Group B Quality Standards. The remaining portions of the feedwater system consist of components governed by Group D Quality Standards. The portion of the feedwater system extending from the reactor vessel up to the second containment isolation valve and including the isolation valves is governed by Group A Quality Standards and is covered in IV.C1.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the feedwater system include the BWR Mark 1, Mark 2, or Mark 3 containment structures (II.B1, II.B2, and II.B3, respectively) and common components (II.B4), the reactor coolant pressure boundary (IV.C1), the main steam system (VIII.B2), the extraction steam system (VIII.C), and the condensate system (VIII.E).

VIII Steam and Power Conversion System
D2. Feedwater System (BWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
D2.1-a D2.1.1	Main feedwater line Piping and fittings (Group B or D)	Carbon steel	Treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
D2.1-b D2.1.1	Main feedwater line Piping and fittings (Group B or D)	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
D2.1-c D2.1.1	Main feedwater line Piping and fittings (Group B or D)	Carbon steel	Treated water	Cumulative fatigue damage/ Fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.3, "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c).	Yes, TLAA
D2.2-a D2.2.1	Valves (control, check, and hand valves) Body and bonnet	Carbon steel	Treated water	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
D2.2-b D2.2.1	Valves (control, check, and hand valves) Body and bonnet	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
D2.3-a D2.3.2	Feedwater pump (steam turbine and motor driven) Suction and discharge lines	Carbon steel	Treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No

VIII Steam and Power Conversion System
D2. Feedwater System (BWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
D2.3-b D2.3.1 D2.3.2	Feedwater pump (steam turbine and motor driven) Casing Suction and discharge lines	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

E. CONDENSATE SYSTEM

E.1 Condensate Lines

E.1.1 Piping and Fittings

E.2 Valves

E.2.1 Body and Bonnet

E.3 Condensate Pumps (Main and Booster Pumps)

E.3.1 Casing

E.4 Condensate Coolers/Condensers

E.4.1 Tubes
E.4.2 Tubesheet
E.4.3 Channel Head
E.4.4 Shell

E.5 Condensate Storage

E.5.1 Tank

E.6 Condensate Cleanup System

E.6.1 Piping and Fittings
E.6.2 Demineralizer
E.6.3 Strainer

E. CONDENSATE SYSTEM

Systems, Structures, and Components

This section comprise the condensate system for both pressurized water reactors (PWRs) and boiling water reactors (BWRs), which extend from the condenser hotwells to the suction of feedwater pumps, including condensate and condensate booster pumps, condensate coolers, condensate cleanup system, and condensate storage tanks. Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," all components that comprise the condensate system are governed by Group D Quality Standards.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the condensate system include the steam turbine system (VIII.A), the main steam system (VIII.B1 and VIII.B2), the feedwater system (VIII.D1 and VIII.D2), the auxiliary feedwater system (VIII.G, PWR only), the reactor water cleanup system (VII.E3, BWR and PWR if used), the open or closed cycle cooling water systems (VII.C1 or VII.C2), and the condensate storage facility.

VIII Steam and Power Conversion System
E. Condensate System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
E.1-a E.1.1	Condensate lines Piping and fittings	Carbon steel	Treated water (BWRs: reactor coolant; PWRs: secondary side water)	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
E.1-b E.1.1	Condensate lines Piping and fittings	Carbon steel	Treated water (BWRs: reactor coolant; PWRs: secondary side water)	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
E.2-a E.2.1	Valves Body and bonnet	Carbon steel	Treated water	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
E.2-b E.2.1	Valves Body and bonnet	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VIII Steam and Power Conversion System
E. Condensate System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
E.3-a E.3.1	Condensate pumps (main and booster pumps) Casing	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
E.4-a E.4.1 E.4.2 E.4.3 E.4.4	Condensate coolers/ condensers (serviced by open-cycle cooling water) Tubes Tubesheet Channel head Shell	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel; shell: carbon steel	Treated water side (condensate side)	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
E.4-b E.4.1 E.4.2 E.4.3 E.4.4	Condensate coolers/ condensers (serviced by open-cycle cooling water) Tubes Tubesheet Channel head Shell	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel; shell: carbon steel	Open-cycle cooling water (raw water) side	Loss of material/ General (carbon steel only), pitting, crevice, and microbiologically influenced corrosion, and biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
E.4-c E.4.1	Condensate coolers/ condensers (serviced by open-cycle cooling water) Tubes	Tubes: stainless steel	Open-cycle cooling water (raw water) side	Buildup of deposit/ Biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No

VIII Steam and Power Conversion System
E. Condensate System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
E.4-d E.4.1 E.4.2 E.4.3 E.4.4	Condensate coolers/ condensers (serviced by closed-cycle cooling water) Tubes Tubesheet Channel head Shell	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel; shell: carbon steel	Treated water side (on other side of condensate)	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
E.4-e E.4.1 E.4.2 E.4.3 E.4.4	Condensate coolers/ condensers (serviced by closed-cycle cooling water) Tubes Tubesheet Channel head Shell	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel; shell: carbon steel	Closed-cycle cooling water side	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M21, "Closed-Cycle Cooling Water System"	No
E.5-a E.5.1	Condensate storage Tank	Carbon steel	<90°C (<194°F) treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VIII Steam and Power Conversion System
E. Condensate System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
E.5-b E.5.1	Condensate storage Tank	Stainless steel	<90°C (<194°F) treated water	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
E.5-c E.5.1	Condensate storage Tank (aboveground, external surface)	Carbon steel	Sun, weather, humidity, and moisture	Loss of material/ General corrosion	Chapter XI.M29, "Aboveground Carbon Steel Tanks"	No
E.5-d E.5.1	Condensate storage Tank (buried, external surface)	Carbon steel	Soil and ground water	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes, detection of aging effects and operating experience are to be further evaluated

VIII Steam and Power Conversion System
E. Condensate System

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
E.6-a E.6.1 E.6.2 E.6.3	Condensate cleanup system Piping and fittings Demineralizer Strainer	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water in BWRVIP-29 (EPRI TR-103515) or PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

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F. STEAM GENERATOR BLOWDOWN SYSTEM (PWR)

F.1 Blowdown Lines

F.1.1 Pipe and Fittings (Group B)
F.1.2 Pipe and Fittings (Group D)

F.2 Valves (including Containment Isolation Valves)

F.2.1 Body and Bonnet

F.3 Blowdown Pump

F.3.1 Casing

F.4 Blowdown Heat Exchanger

F.4.1 Tubes
F.4.2 Tubesheet
F.4.3 Channel Head and Access Cover
F.4.4 Shell and Access Cover

F. STEAM GENERATOR BLOWDOWN SYSTEM (PWR)

Systems, Structures, and Components

This section comprises the steam generator blowdown system for pressurized water reactors (PWRs), which extends from the steam generator through the blowdown condenser and include the containment isolation valves and small bore piping less than NPS 2 (including instrumentation lines).

Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," the portion of the blowdown system extending from the steam generator up to the isolation valve outside the containment and including the isolation valves is governed by Group B or C Quality Standards. The remaining portions of the steam generator blowdown system consist of components governed by Group D Quality Standards.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the blowdown system include the steam generator (IV.D1 and IV.D2) and the open- or closed-cycle cooling water systems (VII.C1 or VII.C2).

VIII Steam and Power Conversion System
F. Steam Generator Blowdown System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
F.1-a F.1.1 F.1.2	Blowdown lines Piping and fittings (Group B) Piping and fittings (Group D)	Carbon steel	Secondary side treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
F.1-b F.1.1 F.1.2	Blowdown lines Piping and fittings (Group B) Piping and fittings (Group D)	Carbon steel	Secondary side treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
F.2-a F.2.1	Valves (including containment isolation valves) Body and bonnet	Carbon steel	Secondary side treated water	Wall thinning (body only)/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion" (body only)	No
F.2-b F.2.1	Valves (including containment isolation valves) Body and bonnet	Carbon steel	Secondary side treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VIII Steam and Power Conversion System
F. Steam Generator Blowdown System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
F.3-a F.3.1	Blowdown pump Casing	Carbon steel	Secondary side treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
F.4-a F.4.1 F.4.2 F.4.3 F.4.4	Blowdown heat exchanger (serviced by open-cycle cooling water) Tubes Tubesheet Channel head and access cover Shell and access cover	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel	Secondary side treated water	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
F.4-b F.4.1 F.4.2 F.4.3 F.4.4	Blowdown heat exchanger (serviced by open-cycle cooling water) Tubes Tubesheet Channel head and access cover Shell and access cover	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel	Open-cycle cooling water (raw water) side	Loss of material/ General (carbon steel only), pitting, crevice, and microbiologically influenced corrosion, and biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
F.4-c F.4.1	Blowdown heat exchanger (serviced by open cycle cooling water) Tubes	Tubes: stainless steel	Open-cycle cooling water (raw water) side	Buildup of deposit/ Biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No

VIII Steam and Power Conversion System
F. Steam Generator Blowdown System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
F.4-d F.4.1 F.4.2 F.4.3 F.4.4	Blowdown heat exchanger (serviced by closed-cycle cooling water) Tubes Tubesheet Channel head and access cover Shell and access cover	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel	Treated water side (other side of steam generator blowdonwn)	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
F.4-e F.4.1 F.4.2 F.4.3 F.4.4	Blowdown heat exchanger (serviced by closed-cycle cooling water) Tubes Tubesheet Channel head and access cover Shell and access cover	Tubes: stainless steel; tubesheet: carbon steel; channel head: carbon steel	Closed-cycle cooling water side	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M21, "Closed-Cycle Cooling Water System"	No

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G. AUXILIARY FEEDWATER SYSTEM (PWR)

G.1 Auxiliary Feedwater Piping

G.1.1 Piping and Fittings (Aboveground)
G.1.2 Piping and Fittings (Buried)

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

G.2.1 Casing
G.2.2 Suction and Discharge Lines

G.3 Valves (Control, Check, Hand, and Containment Isolation Valves)

G.3.1 Body and Bonnet

G.4 Condensate Storage (Emergency)

G.4.1 Tank

G.5 Bearing Oil Coolers (for Steam Turbine Pump)

G.5.1 Shell
G.5.2 Tubes
G.5.3 Tubesheet

G. AUXILIARY FEEDWATER SYSTEM (PWR)

Systems, Structures, and Components

This section comprises the auxiliary feedwater (AFW) system for pressurized water reactors (PWRs), which extends from the condensate storage or backup water supply system to the steam generator or to the main feedwater (MFW) line. They consist of AFW piping, AFW pumps, pump turbine oil coolers, and valves, including the containment isolation valves.

Based on Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants," portions of the AFW system extending from the secondary side of the steam generator up to the second isolation valve and including the containment isolation valves are governed by Group B Quality Standards. In addition, portions of the AFW system that are required for their safety functions and that either do not operate during any mode of normal reactor operation or cannot be tested adequately are also governed by Group B Quality Standards, and the remainder of the structures and components covered in this section are governed by Group C Quality Standards.

Pump and valve internals perform their intended functions with moving parts or with a change in configuration, or they are subject to replacement on the basis of qualified life or specified time period. Accordingly, they are not subject to an aging management review, pursuant to 10 CFR 54.21(a)(1).

Aging management programs for the degradation of the external surfaces of carbon steel components are included in VIII.H.

The system piping includes all pipe sizes, including instrument piping.

System Interfaces

The systems that interface with the auxiliary feedwater system include the steam generator (IV.D1 and IV.D2), the main steam system (VIII.B1), the PWR feedwater system (VIII.D1), the condensate system (VIII.E), and the open- or closed-cycle cooling water systems (VII.C1 or VII.C2).

VIII Steam and Power Conversion System
G. Auxiliary Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.1-a G.1.1	Auxiliary feedwater piping Piping and fittings (aboveground) for Westinghouse steam generators with preheaters	Carbon steel	Treated water >90°C (>194°F)	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No
G.1-b G.1.1	Auxiliary feedwater piping Piping and fittings (aboveground)	Carbon steel	Treated water >90°C (>194°F)	Cumulative fatigue damage/ Fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.3, "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c).	Yes, TLAA
G.1-c G.1.1 G.1.2	Auxiliary feedwater piping Piping and fittings (aboveground) Piping and fittings (buried)	Carbon steel	Treated water	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.1-d G.1.1 G.1.2	Auxiliary feedwater piping Piping and fittings (aboveground) Piping and fittings (buried)	Carbon steel	Untreated water from backup water supply	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion, and biofouling	A plant-specific aging management program is to be evaluated.	Yes, plant specific

VIII Steam and Power Conversion System
G. Auxiliary Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.1-e G.1.2	Auxiliary feedwater piping Piping and fittings (buried) external surface	Carbon steel	Soil and groundwater	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes, detection of aging effects and operating experience are to be further evaluated
G.2-a G.2.1 G.2.2	AFW pumps (steam turbine and motor driven) Casing Suction and discharge lines	Carbon steel	Treated water <90°C (<194°F)	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.3-a G.3.1	Valves (control, check, hand, and containment isolation valves) Body and bonnet	Carbon steel	Treated water <90°C (<194°F)	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VIII Steam and Power Conversion System
G. Auxiliary Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.4-a G.4.1	Condensate storage (emergency) Tank	Carbon steel	Treated water <90°C (<194°F)	Loss of material/ General, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.4-b G.4.1	Condensate storage (emergency) Tank	Stainless steel	Treated water <90°C (<194°F)	Loss of material/ Pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for PWR secondary water in EPRI TR-102134 The AMP is to be augmented by verifying the effectiveness of water chemistry control. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
G.4-c G.4.1	Condensate storage (emergency) Tank (aboveground, external surface)	Carbon steel	Sun, weather, humidity, and moisture	Loss of material/ General corrosion	Chapter XI.M29, "Aboveground Carbon Steel Tanks"	No
G.4-d G.4.1	Condensate storage (emergency) Tank (buried, external surface)	Carbon steel	Soil and groundwater	Loss of material/ General, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M28, "Buried Piping and Tanks Surveillance," or Chapter XI.M34, "Buried Piping and Tanks Inspection"	No Yes, detection of aging effects and operating experience are to be further evaluated

VIII Steam and Power Conversion System
G. Auxiliary Feedwater System (PWR)

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
G.5-a G.5.1 G.5.2 G.5.3	Bearing oil coolers (for steam turbine pump) serviced by open-cycle cooling water Shell Tubes Tubesheet	Stainless steel, carbon steel	Open-cycle cooling water (raw water)	Loss of material/ General (carbon steel only), pitting, crevice, and microbiologically influenced corrosion, and biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
G.5-b G.5.2	Bearing oil coolers (for steam turbine pump) serviced by open-cycle cooling water Tubes	Stainless steel, carbon steel	Open-cycle cooling water (raw water)	Buildup of deposit/ Biofouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
G.5-c G.5.1 G.5.2 G.5.3	Bearing oil coolers (for steam turbine pump) serviced by closed-cycle cooling water Shell Tubes Tubesheet	Stainless steel, carbon steel	Closed-cycle cooling water (treated water)	Loss of material/ General (carbon steel only), pitting, and crevice corrosion	Chapter XI.M21, "Closed-Cycle Cooling Water System"	No
G.5-d G.5.1 G.5.2 G.5.3	Bearing oil coolers (for steam turbine pump) Shell Tubes Tubesheet	Stainless steel, carbon steel	Lubricating oil (possibly contaminated with water)	Loss of material/ General (carbon steel only), pitting, crevice, and microbiologically influenced corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific

H. CARBON STEEL COMPONENTS

H.1 Carbon Steel Components

H.1.1 External Surfaces

H.2 Closure Bolting

H.2.1 In High-Pressure or High-Temperature Systems

H. CARBON STEEL COMPONENTS

Systems, Structures, and Components

This section includes the aging management programs for the degradation of external surfaces of all carbon steel structures and components, including closure boltings in the steam and power conversion system in pressurized water reactors (PWRs) and boiling water reactors (BWRs). For the carbon steel components in PWRs, this section addresses only boric acid corrosion of external surfaces as a result of the dripping borated water that is leaking from an adjacent PWR component.

System Interfaces

The structures and components covered in this section belong to the Steam and Power Conversion Systems in PWRs and BWRs. (For example, see System Interfaces in VIII.A to VIII.G for details.)

VIII Steam and Power Conversion System
H. Carbon Steel Components

Item	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
H.1-a H.1.1	Carbon steel components (PWRs) External Surfaces	Carbon steel, low-alloy steel	Air, leaking and dripping chemically treated borated water up to 340°C (644°F)	Loss of material/ Boric acid corrosion of external surfaces	Chapter XI.M10, "Boric Acid Corrosion"	No
H.1-b H.1.1	Carbon steel components (PWRs and BWRs) External surfaces	Carbon steel, low-alloy steel	Air, moisture, and humidity <100°C (212°F)	Loss of material/ General corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific
H.2-a H.2.1	Closure bolting In high-pressure or high-temperature systems	Carbon steel, low-alloy steel	Air, moisture, humidity, and leaking fluid	Loss of material/ General corrosion	Chapter XI.M18, "Bolting Integrity"	No
H.2-b H.2.1	Closure bolting In high-pressure or high-temperature systems	Carbon steel, low-alloy steel	Air, moisture, humidity, and leaking fluid	Crack initiation and growth/ Cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No

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CHAPTER IX

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CHAPTER X

TIME-LIMITED AGING ANALYSES EVALUATION OF AGING MANAGEMENT PROGRAMS UNDER 10 CFR 54.21(c)(1)(iii)

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TIME-LIMITED AGING ANALYSES: EVALUATION OF AGING MANAGEMENT PROGRAMS UNDER 10 CFR 54.21(c)(1)(iii)

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X.M1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

Program Description

In order not to exceed the design limit on fatigue usage, the aging management program (AMP) monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components.

The AMP addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components that includes, as a minimum, those components selected in NUREG/CR-6260. The sample of critical components can be evaluated by applying environmental correction factors to the existing ASME Code fatigue analyses. Formulas 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 steels.

As evaluated below, this is an acceptable option for managing metal fatigue for the reactor coolant pressure boundary, considering environmental effects. Thus, no further evaluation is recommended for license renewal if the applicant selects this option under 10 CFR 54.21(c)(1)(iii) to evaluate metal fatigue for the reactor coolant pressure boundary.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

2. ***Preventive Actions:*** Maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains.

3. ***Parameters Monitored/Inspected:*** The program monitors all plant transients that cause cyclic strains, which are significant contributions to the fatigue usage factor. The number of plant transients that cause significant fatigue usage for each reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient.

4. ***Detection of Aging Effects:*** The program provides for periodic update of the fatigue usage calculations.

5. ***Monitoring and Trending:*** The program monitors a sample of high fatigue usage locations. As a minimum, this sample is to include the locations identified in NUREG/CR-6260.

6. ***Acceptance Criteria:*** The acceptance criteria involves maintaining the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description.

7. ***Corrective Actions:*** The program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation.

Acceptable corrective actions include a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded, repair, or replacement of the component. For programs that monitor a sample of high fatigue usage locations, corrective actions include a review of additional affected reactor coolant pressure boundary locations.

8. ***Conformation Process:*** Site quality assurance procedures, review and approval processes and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The program reviews industry experience regarding fatigue cracking. Applicable experience with fatigue cracking is to be considered in selecting the monitored locations.

References

NUREG/CR-5704, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,* U.S. Nuclear Regulatory Commission, April 1999.

NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,* U.S. Nuclear Regulatory Commission, March 1995.

NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,* U.S. Nuclear Regulatory Commission, March 1998.

X.S1 CONCRETE CONTAINMENT TENDON PRESTRESS

Program Description

In order to ensure the adequacy of prestressing forces in prestressed concrete containments during the extended period of operation, an applicant can develop an aging management program (AMP) under 10 CFR 54.21(c)(1)(iii).

The AMP consists of an assessment of the results of inspections performed in accordance with the requirements of Subsection IWL of the ASME Section XI Code, as supplemented by the requirements of 10 CFR 50.55a(b)(2)(ix) or (viii) in the later amendment of the regulation. The assessment related to the adequacy of the prestressing force will consist of the establishment of (1) acceptance criteria and (2) trend lines. The acceptance criteria will normally consist of predicted lower limit (PLL) and the minimum required prestressing force, also called minimum required value (MRV). NRC Regulatory Guide 1.35.1 provides guidance for calculating PLL and MRV. The trend line represents the trend of prestressing forces based on the actual measured forces. NRC Information Notice IN 99-10 provides guidance for constructing the trend line. The goal is to keep the trend line above the PLL because, as a result of any inspection performed in accordance with ASME Section XI, Subsection IWL, if the trend line crosses the PLL, the existing prestress in the containment could go below the MRV soon after the inspection and would not meet the requirements of 10 CFR 50.55a(b)(2)(ix)(B) or 10 CFR 50.55a(b)(2)(viii)(B).

As evaluated below, this is an acceptable option to manage containment tendon prestress force, except for the program element/attribute regarding operating experience. Thus, it is recommended that the staff should further evaluate an applicant's operating experience related to the containment prestress force.

The AMP related to the adequacy of prestressing force for containments with grouted tendons will be reviewed on a case-by-case basis.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program addresses the assessment of containment prestressing force when an applicant chooses to perform the containment prestress force TLAA using 10 CFR 54.21(c)(1)(iii).

2. ***Preventive Actions:*** Maintaining the prestress above the MRV, as described under program description above, will ensure that the structural and functional adequacy of the containment are maintained.

3. ***Parameters Monitored:*** The parameters to be monitored are the containment prestressing forces in accordance with requirements specified in Subsection IWL of Section XI of the ASME Code, as incorporated by reference in 10 CFR 50.55a.

4. ***Detection of Aging Effects:*** The loss of containment prestressing forces is detected by the program.

5. ***Monitoring and Trending:*** The estimated and measured prestressing forces are plotted against time and the PLL, MRV, and trending lines developed for the period of extended operation.

6. ***Acceptance Criteria:*** The prestressing force trend lines indicate that existing prestressing forces in the containment would not be below the MRVs prior to the next scheduled inspection, as required by 10 CFR 50.55a(b)(2)(ix)(B) or 10 CFR 50.55a(b)(2)(viii)(B).

7. ***Corrective Actions:*** If acceptance criteria are not met, then either systematic retensioning of tendons or a reanalysis of the containment is warranted to ensure the design adequacy of the containment. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Conformation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** The program incorporates the relevant operating experience that has occurred at the applicant's plant as well as at other plants. The applicable portions of the experience with prestressing systems described in NRC Information Notice 99-10 could be useful for the purpose. However, tendon operating experience could be different at plants with prestressed concrete containments. The difference could be due to the prestressing system design (e.g., button-headed, wedge, or swaged anchorages), environment, and type of reactor (i.e., PWR and BWR). Thus, the applicant's plant-specific operating experience should be further evaluated for license renewal.

References

ASME Section XI, *Rules for In-Service Inspection of Nuclear Power Plant Components, Subsection IWL, Requirements for Class CC Concrete Components of Light-Water Cooled Plants*, 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 99-10, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments,* U. S. Nuclear Regulatory Commission, April 1999.

NRC Regulatory Guide 1.35.1, *Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,* U. S. Nuclear Regulatory Commission, July 1990.

X.E1 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS

Program Description

The Nuclear Regulatory Commission (NRC) has established nuclear station environmental qualification (EQ) requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident [LOCA], high energy line breaks [HELBs] or post-LOCA radiation) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

All operating plants must meet the requirements of 10 CFR 50.49 for certain 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 (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 DOR Guidelines, Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors; NUREG-0588, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment; and Regulatory Guide 1.89, Rev. 1, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants. 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.

EQ programs manage component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the 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 EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAAs) for license renewal.

Under 10 CFR 54.21(c)(1)(iii), plant EQ programs, which implement the requirements of 10 CFR 50.49 (as further defined and clarified by the DOR Guidelines, NUREG-0588, and Regulatory Guide 1.89, Rev. 1), are viewed as aging management programs (AMPs) for license renewal. Reanalysis 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 an EQ program. Important attributes for the reanalysis 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). These attributes are discussed in the "EQ Component Reanalysis Attributes" section.

This reanalysis program can be applied to EQ components now qualified for the current operating term (i.e., those components now qualified for 40 years or more). As evaluated below, this is an acceptable AMP. Thus, no further evaluation is recommended for license renewal if an applicant elects this option under 10 CFR 54.21(c)(1)(iii) to evaluate the TLAA of EQ of electric equipment.

However, Generic Safety Issue (GSI) 168, which is related to low-voltage EQ instrumentation and control cables, is currently an open generic issue. NRC research is ongoing to provide information to resolve it. An applicant is to address GSI-168 in its application for staff review.

EQ Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis 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 an EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to the station's quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods: The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. 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/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach 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 prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation is to 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 on large motors (while the motor is not running). A representative number of temperature measurements are conservatively 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 reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions: EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating 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: The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is to be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is, sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

Evaluation and Technical Basis

1. ***Scope of Program:*** EQ programs apply to certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

2. ***Preventive Actions:*** 10 CFR 50.49 does not require actions that prevent aging effects. EQ program actions that could be viewed as preventive actions include (a) establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit), and (b) where applicable, requiring specific installation, inspection, monitoring or periodic maintenance actions to maintain component aging effects within the bounds of the qualification basis.

3. ***Parameters Monitored/Inspected:*** EQ component qualified life is not based on condition or performance monitoring. However, pursuant to Regulatory Guide 1.89, Rev. 1, such monitoring programs are an acceptable basis to modify a qualified life through reanalysis. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

4. ***Detection of Aging Effects:*** 10 CFR 50.49 does not require the detection of aging effects for in-service components. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

5. ***Monitoring and Trending:*** 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging. EQ program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within the bounds of its qualification basis, or as a means to modify the qualification.

6. ***Acceptance Criteria:*** 10 CFR 50.49 acceptance criteria are that an inservice EQ component is maintained within the bounds of its qualification basis, including (a) its established qualified life and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

7. ***Corrective Actions:*** If an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. 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. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** EQ programs are implemented through the use of station policy, directives, and procedures. EQ programs will continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. EQ program documents identify the applicable environmental conditions for the component locations. EQ program qualification files are maintained at the plant site in an auditable form for the duration of the installed life of the component. EQ program documentation is controlled under the station's quality assurance program. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of inservice aging.

References

10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, 2000.

DOR Guidelines, *Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,* November 1979.

NRC Regulatory Guide 1.89, Rev. 1, *Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,* U. S. Nuclear Regulatory Commission, June 1984.

NUREG-0588, *Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,* U. S. Nuclear Regulatory Commission, July 1981.

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CHAPTER XI

AGING MANAGEMENT PROGRAMS (AMPs)

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AGING MANAGEMENT PROGRAMS (AMPs)

XI.E3 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

XI.M1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

Program Description

The Code of Federal Regulations, 10 CFR 50.55a, imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWB, IWC, and IWD, respectively, in the 1995 edition through the 1996 addenda. The program generally includes periodic visual, surface, and/or volumetric examination and leakage test of all Class 1, 2, and 3 pressure-retaining components and their integral attachments.

The ASME Section XI inservice inspection program in accordance with Subsections IWB, IWC, or IWD has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants. However, in certain cases, the ASME inservice inspection program is to be augmented to manage effects of aging for license renewal and is so identified in the GALL report.

Evaluation and Technical Basis

1. ***Scope of Program:*** The ASME Section XI program provides the requirements for ISI, repair, and replacement. The components within the scope of the program are specified in Subsections IWB-1100, IWC-1100, and IWD-1100 for Class 1, 2, and 3 components, respectively, and include all pressure-retaining components and their integral attachments in light-water cooled power plants. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

2. ***Preventive Actions:*** The ASME Section XI does not provide guidance on methods to mitigate degradation.

3. ***Parameters Monitored/Inspected:*** The ASME Section XI ISI program detects degradation of components by using the examination and inspection requirements specified in ASME Section XI Tables IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, for Class 1, 2, or 3 components.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal crack initiation and growth; loss of material due to corrosion; leakage of coolant; and indications of degradation due to wear or stress relaxation, such as verification of clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections.

   Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively, for Class 1, 2, and 3 components. The tables specify the extent and schedule of the inspection and examination methods for the components of the pressure-retaining boundaries. Alternative approved methods that meet the requirements of IWA-2240 are also specified in these tables.

The program uses three types of examination — visual, surface, and volumetric — in accordance with the general requirements of Subsection IWA-2000. Visual VT-1 examination detects discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surface of components. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test. Visual VT-3 examination (a) determines the general mechanical and structural condition of components and their supports by verifying parameters, such as clearances, settings, and physical displacements; (b) detects discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion; and (c) observes conditions that could affect operability or functional adequacy of constant-load and spring-type components and supports.

Surface examination uses magnetic particle, liquid penetrant, or eddy current examinations to indicate the presence of surface discontinuities and flaws.

Volumetric examination uses radiographic, ultrasonic, or eddy current examinations to indicate the presence of discontinuities or flaws throughout the volume of material included in the inspection program.

For BWRs, the nondestructive examination (NDE) techniques appropriate for inspection of vessel internals and their implementation needs, including the uncertainties inherent in delivering and executing and NDE technique in a boiling water reactor (BWR), are included in the approved boiling water reactor vessel and internals project (BWRVIP)-03. Also, an applicant may use the guidelines of the approved BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry.

The ASME Section XI examination categories used in this report are given below. These examination categories are based on the 1989 edition of Section XI of the ASME Code; any differences in the examination categories in the 1995 edition through the 1996 addenda from those in the 1989 edition are identified.

Class 1 Components, Table IWB-2500-1

Examination category B-B for pressure-retaining welds in vessels other than reactor vessels: This category specifies volumetric examination of circumferential and longitudinal shell-to-head welds and circumferential and meridional head welds in pressurizers, and circumferential and meridional head welds and tubesheet-to-head welds in steam generators (primary side). The welds selected during the first inspection interval are reexamined during successive inspection intervals.

Examination category B-D, for full penetration welds of nozzles in reactor vessels, pressurizers, steam generators (primary side), and heat exchangers (primary side): This category specifies volumetric examination of all nozzle-to-vessel welds and the nozzle inside radius.

Examination category B-E, for pressure-retaining partial penetration welds in vessels: This category specifies visual VT-2 examination of partial penetration welds in nozzles and penetrations in reactor vessels and pressurizers during the hydrostatic test. In the 1995 edition of the ASME Code, examination category B-E is covered under examination category B-P.

Examination category B-F, for pressure-retaining dissimilar metal welds in reactor vessels, pressurizers, steam generators, heat exchangers, and piping: This category specifies volumetric examination of the inside diameter (ID) region and surface examination of the outside diameter (OD) surface for all nozzle-to-safe end butt welds of nominal pipe size (NPS) 4 in. or larger. Only surface examination is conducted for all butt welds less than NPS 4 in. and for all nozzle-to-safe end socket welds. Examinations are required for each safe end weld in each loop and connecting branch of the reactor coolant system. In the 1995 edition of the ASME Code, examination category B-F for piping is covered under examination category B-J for all pressure-retaining welds in piping.

Examination category B-G-1 for pressure-retaining bolting greater than 2 in. in diameter, and category B-G-2 for pressure-retaining bolting less than 2 in. in diameter in reactor vessels, pressurizers, steam generators, heat exchangers, piping, pumps, and valves: Category B-G-1 specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole; and surface and volumetric examination of studs when removed; volumetric examination of flange threads; and visual VT-1 examination of the surfaces of nuts, washers, and bushings. Category B-G-2 specifies visual VT-1 examination of the surfaces of nuts, washers, and bushings. For heat exchangers, piping, pumps, and valves, examinations are limited to components selected for examination under examination categories B-B, B-J, B-L-2, and B-M-2.

Examination category B-H for integral attachments for vessels: This category specifies volumetric or surface examination of essentially 100% of the length of the attachment weld at each attachment subject to examination.

Examination category B-J for pressure-retaining welds in piping: This category specifies volumetric examination of the ID region and surface examination of the OD for circumferential and longitudinal welds in each pipe or branch run NPS 4 in. or larger. Surface examination is conducted for circumferential and longitudinal welds in each pipe or branch run less than NPS 4 in. and for all socket welds. The pipe welds selected during the first inspection interval are reexamined during each successive inspection interval.

Examination category B-L-1, for pressure-retaining welds in pump casing, and category B-L-2, for pump casing: Category B-L-1 specifies volumetric examination of all welds, and category B-L-2 specifies visual VT-3 examination of internal surfaces of the pump casing. All welds from at least one pump in each group of pumps performing similar functions in the system (such as recirculating coolant pumps) are inspected during each inspection interval. Visual examination is required only when the pump is disassembled for maintenance, repair, or volumetric examination, but one pump in a particular group of pumps is visually examined at least once during the inspection interval.

Examination category B-M-1, for pressure-retaining welds in valve bodies and category B-M-2, for valve bodies: Category B-M-1 specifies volumetric examination for all welds in valve bodies NPS 4 in. or larger, and surface examination of OD surfaces for all welds in valve bodies less than NPS 4 in. Category B-M-2 specifies visual VT-3 examination of internal surfaces of valve bodies. All welds from at least one valve in each group of valves that are of the same size, construction design (such as globe, gate, or check valves), and manufacturing method, and that perform similar functions in the system (such as the containment isolation valve) are inspected during each inspection interval. Visual examination is required only when the valve is disassembled for maintenance, repair, or volumetric examination, but one valve in a particular group of valves is visually examined at least once during the inspection interval.

Examination category B-N-1, for the interior of reactor vessels: Category B-N-1 specifies visual VT-3 examination of interior surfaces that are made accessible for examination by removal of components during normal refueling outages. *Examination category B-N-2, for integrally welded core support structures and interior attachments to reactor vessels*: Category B-N-2 specifies visual VT-1 examination of all accessible welds in interior attachments within the beltline region; visual VT-3 examination of all accessible welds in interior attachments beyond the beltline region; and, for BWRs, visual VT-3 examination of all accessible surfaces in the core support structure. *Examination category B-N-3, which is applicable to pressurized water reactors (PWRs), for removable core support structures*: Category B-N-3 specifies visual VT-3 examination of all accessible surfaces of reactor core support structures that can be removed from the reactor vessel.

Examination category B-O, for pressure-retaining welds in control rod housing: This category specifies volumetric or surface examination of the control rod drive (CRD) housing welds, including the weld buttering.

Examination category B-P, for all pressure-retaining components: This category specifies visual VT-2 examination of all pressure-retaining boundary components during the system leakage test and hydrostatic test (IWA-5000 and IWB-5000). The pressure-retaining boundary during the system leakage test corresponds to the reactor coolant system boundary, with all valves in the normal position, which is required for normal reactor operation startup. However, VT-2 visual examination extends to and includes the second closed valve at the boundary extremity. The 1995 edition of the ASME Code eliminates the hydrostatic test because equivalent results are obtained from the leakage test. The pressure-retaining boundary for the hydrostatic test (1989 edition) and system leakage test (1995 edition) conducted at or near the end of each inspection interval extends to all Class 1 pressure-retaining components within the system boundary.

Class 2 Components, Table IWC-2500-1

Examination category C-A, for pressure-retaining welds in pressure vessels: This category specifies volumetric examination of circumferential welds at gross structural discontinuities, such as junctions between shells of different thickness or cylindrical shell-to-conical shell junctions, and head-to-shell, shell (or head)-to-flange, and tubesheet-to-shell welds.

Examination category C-F-1, for pressure-retaining welds in austenitic stainless steel or high-alloy piping: This category specifies, for circumferential and longitudinal welds in each pipe or branch run NPS 4 in. or larger, volumetric and surface examination of the ID region, and surface examination of the OD surface for piping welds ≥3/8 in. nominal wall thickness for piping >NPS 4 in. or for piping welds >1/5 in. nominal wall thickness for piping ≥NPS 2 in. and ≤NPS 4 in. Surface examination is conducted for circumferential and longitudinal welds in pipe branch connections of branch piping ≥NPS 2 in. and for socket welds.

Examination category C-G, for all pressure-retaining welds in pumps and valves: This category specifies surface examination of either the inside or outside surface of all welds in the pump casing and valve body. In a group of multiple pumps or valves of similar design, size, function, and service in a system, examination of only one pump or one valve among each group of multiple pumps or valves is required to detect the loss of intended function of the pump or valve.

Examination category C-H, for all pressure-retaining components: This category specifies visual VT-2 examination during system pressure tests (IWA-5000 and IWC-5000) of all pressure-retaining boundary components. The pressure-retaining boundary includes only those portions of the system required to operate or support the safety function, up to and including the first normally closed valve (including a safety or relief valve) or valve capable of automatic closure when the safety function is required. The 1995 edition of the ASME Code eliminates the hydrostatic test because equivalent results are obtained from the leakage test.

Class 3 Components, Table IWD-2500-1

Examination category D-A (1989 edition), for systems in support of reactor shutdown function, and category D-B (1989 edition), for systems in support of emergency core cooling, containment heat removal, atmosphere cleanup, and reactor residual heat removal: Categories D-A and D-B specify visual VT-2 examination during system pressure tests (IWA-5000 and IWD-5000) of all pressure-retaining boundary components. The pressure-retaining boundary extends up to and includes the first normally closed valve or valve capable of automatic closure as required to perform the safety-related system function. Examination categories D-A and D-B, from the 1989 edition of the ASME Code, have been combined into examination category D-B for all pressure-retaining components in the 1995 edition of the ASME Code.

5. ***Monitoring and Trending:*** For Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. If flaw indications or relevant conditions of degradation are evaluated in accordance with IWB-3100 or IWC-3100, and the component is qualified as acceptable for continued service, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-2410 for Class 1 components and for the next inspection period of IWC-2410 for Class 2 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB-2430, IWC-2430, or IWD-2430 (1995 edition) for Class 1, 2, or, 3 components, respectively.

6. ***Acceptance Criteria:*** Any indication or relevant conditions of degradation detected are evaluated in accordance with IWB-3000, IWC-3000, or IWD-3000, for Class 1, 2, or 3 components, respectively. Examination results are evaluated in accordance with IWB-3100 or IWC-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB-3500 or IWC-3400 and IWC-3500, respectively, for Class 1 or Class 2 and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500 or IWC-3500, are evaluated by using the analytical procedures of IWB-3600 or IWC-3600, respectively, for Class 1 or Class 2 and 3 components. Approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively.

7. ***Corrective Actions:*** For Class 1, 2, and 3, respectively, repair is in conformance with IWB-4000, IWC-4000, and IWD-4000, and replacement according to IWB-7000, IWC-7000, and IWD-7000. Approved BWRVIP-44 and BWRVIP-45 documents, respectively, provide guidelines for weld repair of nickel alloys and for weldability of irradiated structural components. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Because the ASME Code is a consensus document that has been widely used over a long period, it has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants (see Chapter I of the GALL report, Vol. 2).

    Some specific examples of operating experience of component degradation are as follows:

    BWR: Cracking due to intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel alloys. The IGSCC has also occurred in a number of vessel internal components, such as core shrouds, access hole covers, top guides, and core spray spargers (NRC IE Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC General Letter [GL] 94-03, and NUREG-1544). Crack initiation and growth due to thermal and mechanical loading have occurred in high-pressure coolant injection (HPCI) piping (NRC IN 89-80) and instrument lines NRC Licensee Event Report [LER] 50-249/99-003-1). Jet pump BWRs are designed with access holes in the shroud support plate at the bottom of the annulus between the core shroud and the reactor vessel wall. These holes are used for access during construction and are subsequently closed by welding a plate over the hole. Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in access hole covers. Failure of the isolation condenser tube bundles due to thermal fatigue and transgranular stress corrosion cracking (TGSCC) due to leaky valves has also occurred (NRC LER 50-219/98-014).

    PWR Primary System: Although the primary pressure boundary piping of PWRs has generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry, SCC has occurred in safety injection lines (NRC IN 97-19 and 84-18), charging pump casing cladding (NRC IN 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), CRD seal housing (NRC Inspection Report 50-255/99012), and safety-related stainless steel (SS) piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Cracking has occurred in SS baffle former bolts in a number of foreign plants (NRC IN 98-11) and has now been observed in plants in the United States. Crack initiation and growth due to thermal and mechanical loading has occurred in high-pressure injection and safety injection piping (NRC IN 97-46 and NRC BL 88-08).

    PWR Secondary System: Steam generator tubes have experienced outside diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), wastage, and pitting (NRC IN 97-88). Carbon steel support plates in steam generators have experienced general corrosion. Steam generator shells have experienced pitting and stress corrosion cracking (NRC INs 82-37, 85-65, and 90-04).

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BWRVIP-14, *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, (EPRI TR-105873, July 11, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-14, December 3, 1999.

BWRVIP-44, *Underwater Weld Repair of Nickel Alloy Reactor Vessel Internals, (EPRI TR-108708, April 3, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-44, June 9, 1999.

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BWRVIP-59, *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals, (EPRI TR-108710),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

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NRC Information Notice 84-18, *Stress Corrosion Cracking in PWR Systems*, U.S. Nuclear Regulatory Commission, March 7, 1984.

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NRC Information Notice 88-03, *Cracks in Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, February 2, 1988.

NRC Information Notice 89-80, *Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping*, U.S. Nuclear Regulatory Commission, December 1, 1989.

NRC Information Notice 90-04, *Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators*, U.S. Nuclear Regulatory Commission, January 26, 1990.

NRC Information Notice 91-05, *Intergranular Stress Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles*, U.S. Nuclear Regulatory Commission, January 30, 1991.

NRC Information Notice 92-57, *Radial Cracking of Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, August 11, 1992.

NRC Information Notice 94-63, *Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks*, U.S. Nuclear Regulatory Commission, August 30, 1994.

NRC Information Notice 95-17, *Reactor Vessel Top Guide and Core Plate Cracking*, U.S. Nuclear Regulatory Commission, March 10, 1995.

NRC Information Notice 97-19, *Safety Injection System Weld Flaw at Sequoyah Nuclear Power Plant, Unit 2*, U.S. Nuclear Regulatory Commission, April 18, 1997.

NRC Information Notice 97-46, *Unisolable Crack in High-Pressure Injection Piping*, U.S. Nuclear
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NRC Information Notice 97-88, *Experiences During Recent Steam Generator Inspections*, U.S. Nuclear Regulatory Commission, December 16, 1997.

NRC Information Notice 98-11, *Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants*, U.S. Nuclear Regulatory Commission, March 25, 1998.

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NRC Licensee Event Report LER # 99-003-01, *Supplement to Reactor Recirculation B Loop, High Pressure Flow Element Venturi Instrument Line Steam Leakage Results in Unit 3 Shutdown Due to Fatigue Failure of Socket Welded Pipe Joint*, U.S. Nuclear Regulatory Commission, August 30, 1999.

XI.M2 WATER CHEMISTRY

Program Description

The main objective of this program is to mitigate damage caused by corrosion and stress corrosion cracking (SCC). The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on guidelines in the boiling water reactor vessel and internals project (BWRVIP)-29 (Electric Power Research Institute [EPRI] TR-103515). The BWRVIP-29 has three sets of guidelines: one for primary water, one for condensate and feedwater, and one for control rod drive (CRD) mechanism cooling water. The water chemistry program for pressurized water reactors (PWRs) relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry.

The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry program may not be effective in low flow or stagnant flow areas. Accordingly, in certain cases as identified in the GALL report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. As discussed in the GALL report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or crack initiation and growth. Water chemistry control is in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs; EPRI TR-105714, Rev. 3, for primary water chemistry in PWRs; EPRI TR-102134, Rev. 3, for secondary water chemistry in PWRs; or later revisions or updates of these reports as approved by the staff.

2. ***Preventive Actions:*** The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice and pitting corrosion and crack initiation and growth caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC.

3. ***Parameters Monitored/Inspected:*** The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemistry integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

   BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommends that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

PWR Primary Water Chemistry: The EPRI guidelines (EPRI TR-105714) for PWR primary water chemistry recommend that the concentration of chlorides, fluorides, sulfates, lithium, and dissolved oxygen and hydrogen are monitored and kept below the recommended levels to mitigate SCC of austenitic stainless steel, Alloy 600, and Alloy 690 components. TR-105714 provides guidelines for chemistry control in PWR auxiliary systems such as boric acid storage tank, refueling water storage tank, spent fuel pool, letdown purification systems, and volume control tank.

PWR Secondary Water Chemistry: The EPRI guidelines (EPRI TR-102134) for PWR secondary water chemistry recommend monitoring and control of chemistry parameters (e.g., pH level, cation conductivity, sodium, chloride, sulfate, lead, dissolved oxygen, iron, copper, and hydrazine) to mitigate steam generator tube degradation caused by denting, intergranular attack (IGA), outer diameter stress corrosion cracking (ODSCC), or crevice and pitting corrosion. The monitoring and control of these parameters, especially the pH level, also mitigates general (carbon steel components), crevice, and pitting corrosion of the steam generator shell and the balance of plant materials of construction (e.g., carbon steel, stainless steel, and copper).

4. ***Detection of Aging Effects:*** This is a mitigation program and does not provide for detection of any aging effects, such as loss of material and crack initiation and growth.

   In certain cases as identified in the GALL report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

5. ***Monitoring and Trending:*** The frequency of sampling water chemistry varies (e.g., continuous, daily, weekly, or as needed) based on plant operating conditions and the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

6. ***Acceptance Criteria:*** Maximum levels for various contaminants are maintained below the system specific limits as indicated by the limits specified in the corresponding EPRI water chemistry guidelines. Any evidence of the presence of aging effects or unacceptable water chemistry results is evaluated, the root cause identified, and the condition corrected.

7. ***Corrective Actions:*** When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range and within the time period specified in the EPRI water chemistry guidelines. As discussed in

the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants such as chlorides, fluorides, sulfates, dissolved oxygen, and hydrogen peroxide to within the acceptable ranges. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process.

9. ***Administrative Controls:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing administrative controls.

10. ***Operating Experience:*** The EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use. The specific examples of operating experience are as follows:

    BWR: Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel-base alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal (RHR) systems, and reactor water cleanup (RWCU) system piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers (Nuclear Regulatory Commission [NRC] Information Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC General Letter [GL] 94-03, and NUREG-1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR-6001).

    PWR Primary System: The primary pressure boundary piping of PWRs has generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry. However, the potential for SCC exists due to inadvertent introduction of contaminants into the primary coolant system from unacceptable levels of contaminants in the boric acid; introduction through the free surface of the spent fuel pool, which can be a natural collector of airborne contaminants; or introduction of oxygen during cooldown (NRC IN 84–18). Ingress of demineralizer resins into the primary system has caused IGSCC of Alloy 600 vessel head penetrations (NRC IN 96-11, NRC GL 97-01). Inadvertent introduction of sodium thiosulfate into the primary system has caused IGSCC of steam generator tubes. The SCC has occurred in safety injection lines (NRC INs 97-19 and 84-18), charging pump casing cladding (NRC INs 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water stress corrosion cracking (PWSCC) (NRC INs 89-33, 94-87, 97-88, 90-10, and 96-11; NRC Bulletin 89-01 and its two supplements).

    PWR Secondary System: Steam generator tubes have experienced ODSCC, IGA, wastage, and pitting (NRC IN 97-88, NRC GL 95-05). Carbon steel support plates in steam generators have experienced general corrosion. The steam generator shell has experienced pitting and stress corrosion cracking (NRC INs 82-37, 85-65, and 90-04).

Such operating experience has provided feedback to revisions of the EPRI water chemistry guideline documents.

References

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EPRI TR-102134, *PWR Secondary Water Chemistry Guideline-Revision 3*, Electric Power Research Institute, Palo Alto, CA, May 1993.

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NRC IE Bulletin 80-13, *Cracking in Core Spray Piping*, U.S. Nuclear Regulatory Commission, May 12, 1980.

NRC IE Bulletin 89-01, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, May 15, 1989.

NRC IE Bulletin 89-01, Supplement 1, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, November 14, 1989.

NRC IE Bulletin 89-01, Supplement 2, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, June 28, 1991.

NRC Generic Letter 94-03, *Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors*, U.S. Nuclear Regulatory Commission, July 25, 1994.

NRC Generic Letter 95-05, *Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking*, U.S. Nuclear Regulatory Commission, August 3, 1995.

NRC Generic Letter 97-01, *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations*, U.S. Nuclear Regulatory Commission, April 1,1997.

NRC Information Notice 80-38, *Cracking In Charging Pump Casing Cladding*, U.S. Nuclear Regulatory Commission, October 31, 1980.

NRC Information Notice 82-37, *Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating PWR*, U.S. Nuclear Regulatory Commission, September 16,1982.

NRC Information Notice 84-18, *Stress Corrosion Cracking in Pressurized Water Reactor Systems*, U.S. Nuclear Regulatory Commission, March 7, 1984.

NRC Information Notice 85-65, *Crack Growth in Steam Generator Girth Welds*, U.S. Nuclear Regulatory Commission, July 31, 1985.

NRC Information Notice 89-33, *Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, March 23, 1989.

NRC Information Notice 90-04, *Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators*, U.S. Nuclear Regulatory Commission, January 26, 1990.

NRC Information Notice 90-10, *Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600*, U.S. Nuclear Regulatory Commission, February 23, 1990.

NRC Information Notice 91-05, *Intergranular Stress Corrosion Cracking In Pressurized Water Reactor Safety Injection Accumulator Nozzles*, U.S. Nuclear Regulatory Commission, January 30, 1991.

NRC Information Notice 94-63, *Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks*, U.S. Nuclear Regulatory Commission, August 30, 1994.

NRC Information Notice 94-87, *Unanticipated Crack in a Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, December 22, 1994.

NRC Information Notice 95-17, *Reactor Vessel Top Guide and Core Plate Cracking*, U.S. Nuclear Regulatory Commission, March 10, 1995.

NRC Information Notice 96-11, *Ingress of Demineralizer Resins Increase Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations*, U.S. Nuclear Regulatory Commission, February 14, 1996.

NRC Information Notice 97-19, *Safety Injection System Weld Flaw at Sequoyah Nuclear Power Plant, Unit 2*, U.S. Nuclear Regulatory Commission, April 18, 1997.

NRC Information Notice 97-88, *Experiences during Recent Steam Generator Inspections*, U.S. Nuclear Regulatory Commission, December 16, 1997.

NUREG-1544, *Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components*, U.S. Nuclear Regulatory Commission, March 1996.

NUREG/CR-6001, *Aging Assessment of BWR Standby Liquid Control Systems,* G. D. Buckley, R. D. Orton, A. B. Johnson Jr., and L. L. Larson, 1992.

XI.M3 Reactor Head Closure Studs

Program Description

This program includes (a) inservice inspection (ISI) in conformance with the requirements of the American Society of Mechanical Engineers (ASME), Code, Section XI, Subsection IWB (1995 edition through the 1996 addenda), Table IWB 2500-1, and (b) preventive measures to mitigate cracking.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes (a) ISI to detect crack initiation and growth due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC); loss of material due to wear; and coolant leakage from reactor vessel closure stud bolting for both boiling water reactors (BWRs) and pressurized water reactors (PWRs), and (b) preventive measures of NRC Regulatory Guide 1.65 to mitigate cracking. The program is applicable to closure studs and nuts constructed from materials with a maximum tensile strength limited to less than 1,172 MPa (170 ksi) (Nuclear Regulatory Commission [NRC] Regulatory Guide [RG} 1.65).

2. ***Preventive Actions:*** Preventive measures include avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement and to use manganese phosphate or other acceptable surface treatments and stable lubricants (RG 1.65). Implementation of these mitigation measures is an effective option for reducing SCC or IGSCC and for this program to be effective.

3. ***Parameters Monitored/Inspected:*** The ASME Section XI ISI program detects and sizes cracks, detects loss of material, and detects coolant leakage by following the examination and inspection requirements specified in Table IWB-2500-1.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal crack initiation and growth, loss of material due to corrosion or wear, and leakage of coolant.

   The program uses visual, surface, and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. Surface examination uses magnetic particle, liquid penetration, or eddy current examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic, ultrasonic, or eddy current examinations to indicate the presence of discontinuities or flaws throughout the volume of material. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test.

   Components are examined and tested as specified in Table IWB-2500-1. Examination category B-G-1, for pressure-retaining bolting greater than 2 in. in diameter in reactor vessels specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole, and surface and volumetric examination of studs when removed. Also specified are volumetric examination of flange threads and visual VT-1 examination of surfaces of nuts, washers, and bushings. Examination category B-P for all pressure-retaining components, specifies visual VT-2 examination of all pressure-retaining boundary components during the system leakage test and the system hydrostatic test.

5. ***Monitoring and Trending:*** The Inspection schedule of IWB-2400, and the extent and frequency of IWB-2500-1 provide timely detection of cracks, loss of material, and leakage.

6. ***Acceptance Criteria:*** Any indication or relevant condition of degradation in closure stud bolting is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

7. ***Corrective Actions:*** Repair and replacement are in conformance with the requirements of IWB-400 and IWB-7000, respectively, and the material and inspection guidance of RG 1.65. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The SCC has occurred in BWR pressure vessel head studs (Stoller 1991). The aging management program (AMP) has provisions regarding inspection techniques and evaluation, material specifications, corrosion prevention, and other aspects of reactor pressure vessel head stud cracking. Implementation of the program provides reasonable assurance that the effects of cracking due to SCC or IGSCC and loss of material due to wear will be adequately managed so that the intended functions of the reactor head closure studs and bolts will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

NRC Regulatory Guide 1.65, *Material and Inspection for Reactor Vessel Closure Studs*, U.S. Nuclear Regulatory Commission, October 1973.

Stoller, S. M., *Reactor Head Closure Stud Cracking, Material Toughness Outside FSAR - SCC in Thread Roots*, Nuclear Power Experience, BWR-2, III, 58, p. 30, 1991.

XI.M4 BWR VESSEL ID ATTACHMENT WELDS

Program Description

The program includes (a) inspection and flaw evaluation in accordance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP)-48 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-29 (Electric Power Research Institute [EPRI] TR-103515) to ensure the long-term integrity and safe operation of boiling water reactor (BWR) vessel inside diameter (ID) attachment welds.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the effects of crack initiation and growth due to stress corrosion cracking (SCC), including intergranular stress corrosion cracking (IGSCC). The program contains preventive measures to mitigate SCC; inservice inspection (ISI) to detect cracking and monitor the effects of cracking on the intended function of the components; and repair and/or replacement, as needed, to maintain the ability to perform the intended function.

   The guidelines of BWRVIP-48 include inspection recommendations and evaluation methodologies for the attachment welds between the vessel wall and vessel ID brackets that attach safety-related components to the vessel (e.g., jet pump riser braces and core-spray piping brackets). In some cases, the attachment is a simple weld; in others, it includes a weld build-up pad on the vessel. The BWRVIP-48 guidelines include information on the geometry of the vessel ID attachments; evaluate susceptible locations and safety consequence of failure; provide recommendations regarding the method, extent, and frequency of inspection; and discuss acceptable methods for evaluating the structural integrity significance of flaws detected during these examinations.

2. ***Preventive Actions:*** The BWRVIP-48 provides guidance on detection, but does not provide guidance on methods to mitigate cracking. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Section XI.M2, "Water Chemistry."

3. ***Parameters Monitored/Inspected:*** The program monitors the effects of SCC and IGSCC on the intended function of vessel attachment welds by detection and sizing of cracks by ISI in accordance with the guidelines of approved BWRVIP-48 and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB 2500-1 (1995 edition through the 1996 addenda). An applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by BWRVIP-48 guidelines are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function. Inspection can reveal crack initiation and growth. Vessel ID attachment welds are inspected in accordance with the requirements of ASME Section XI, Subsection IWB, examination category B-N-2. The Section XI inspection specifies visual VT-1 examination to detect discontinuities and imperfections on the surfaces of components and visual VT-3

examination to determine the general mechanical and structural condition of the component supports. The inspection and evaluation guidelines of BWRVIP-48 recommend more stringent inspections for certain selected attachments. The guidelines recommend enhanced visual VT-1 examination of all safety-related attachments and those nonsafety-related attachments identified as being susceptible to IGSCC. Visual VT-1 examination is capable of achieving 1/32 in. resolution; the enhanced visual VT-1 examination method is capable of achieving a 1-mil wire resolution. The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals and their implementation needs, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03.

5. ***Monitoring and Trending:*** Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-48 guidelines provide timely detection of cracks. If flaws are detected, the scope of examination is expanded.

6. ***Acceptance Criteria:*** Any indication detected is evaluated in accordance with ASME Section XI or the staff-approved BWRVIP-48 guidelines. Applicable and approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

7. ***Corrective Actions:*** Repair and replacement procedures are equivalent to those requirements in the ASME Section XI. Repair is in conformance with IWB-4000 and replacement occurs according to IWB-7000. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-48, as modified, will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with 10 CFR Part 50, Appendix B, corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-48, as modified, will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with the 10 CFR Part 50, Appendix B, confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Cracking due to SCC/IGSCC has occurred in BWR components. The program guidelines are based on evaluation of available information, including BWR inspection data and information on the elements that cause IGSCC, to determine which attachment welds may be susceptible to cracking. Implementation of the program provides reasonable assurance that crack initiation and growth will be adequately managed and the intended functions of the vessel ID attachments will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-03, *BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines, (EPRI TR-105696 R1, March 30, 1999),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-03, July 15, 1999.

BWRVIP-14, *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, (EPRI TR-105873, July 11, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-14, December 3, 1999.

BWRVIP-29, *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry, (EPRI TR-103515),* Electric Power Research Institute, Palo Alto, CA, February 1994.

BWRVIP-48, *BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines, (EPRI TR-108724, February 1998),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-48 for Compliance with the License Renewal Rule (10 CFR Part 54), January 17, 2001.

BWRVIP-59, *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals, (EPRI TR-108710),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-60, *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals, (EPRI TR-108709, April 14, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-62, *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection, (EPRI TR-108705),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

XI.M5 BWR FEEDWATER NOZZLE

Program Description

This program includes (a) enhanced inservice inspection (ISI) in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, Table IWB 2500-1 (1995 edition through the 1996 addenda) and the recommendation of General Electric (GE) NE-523-A71-0594, and (b) system modifications to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of boiling water reactor (BWR) feedwater nozzle.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes enhanced ISI to monitor the effects of crack initiation and growth on the intended function of the component and systems modifications to mitigate cracking.

2. ***Preventive Actions:*** Mitigation occurs by systems modifications, such as removal of stainless steel cladding and installation of improved spargers. Mitigation is also accomplished by changes to plant-operating procedures, such as improved feedwater control and rerouting of the reactor water cleanup system, to decrease the magnitude and frequency of temperature fluctuations.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors the effects of cracking on the intended function of the component by detection and sizing of cracks by ISI in accordance with ASME Section XI, Subsection IWB and the recommendation of GE NE-523-A71-0594, as described below.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection prescribed by the program are designed to ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal crack initiation and growth. The GE NE-523-A71-0594 specifies UT of specific regions of the blend radius and bore. The UT examination techniques and personnel qualifications are in accordance with to the guidelines of GE NE-523-A71-0594. Based on the inspection method and techniques and plant-specific fracture mechanics assessments, the inspection schedule is in accordance with Table 6-1 of GE NE-523-A71-0594. Leakage monitoring may be used to modify the inspection interval.

5. ***Monitoring and Trending:*** Inspections scheduled in accordance with GE NE-523-A71-0594 provides timely detection of cracks.

6. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

7. ***Corrective Actions:*** Repair is in conformance with IWB-4000 and replacement in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report,

the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Cracking has occurred in several BWR plants (NUREG-0619, NRC Generic Letter 81-11). This AMP has been implemented for nearly 20 years and found to be effective in managing the effect of cracking on the intended function of feedwater nozzles.

References

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

GE-NE-523-A71-0594, Rev. 1, *Alternate BWR Feedwater Nozzle Inspection Requirements,* BWR Owner's Group, August 1999.

NRC Generic Letter 81-11, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking (NUREG-0619),* U.S. Nuclear Regulatory Commission, February 29, 1981.

NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking,* U.S. Nuclear Regulatory Commission, November 1980.

XI.M6 BWR CONTROL ROD DRIVE RETURN LINE NOZZLE

Program Description

This program includes (a) enhanced inservice inspection (ISI) in conformance with the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, Table IWB 2500-1 (1995 edition through the 1996 addenda) and the recommendations of NUREG-0619, and (b) system modifications and maintenance programs to mitigate cracking. The program specifies periodic liquid penetrant and ultrasonic inspection of critical regions of boiling water reactor (BWR) control rod drive return line (CRDRL) nozzle.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes systems modifications, enhanced ISI, and maintenance programs to monitor the effects of crack initiation and growth on the intended function of CRDRL nozzles.

2. ***Preventive Actions:*** Mitigation occurs by system modifications, such as rerouting the CRDRL to a system that connects to the reactor vessel. For some classes of BWRs, or those that can prove satisfactory system operation, mitigation also is accomplished by confirmation of proper return flow capability, two-pump operation and cutting and capping the CRDRL nozzle without rerouting.

3. ***Parameters Monitored/ Inspected:*** The aging management program (AMP) monitors the effects of cracking on the intended function of the component by detecting and sizing cracks by ISI in accordance with Table IWB 2500-1 and NUREG-0619.

4. ***Detection of Aging Effects:*** The extent and schedule of inspection, as delineated in NUREG 0619, assures detection of cracks before the loss of intended function of the component. Inspection recommendations include liquid penetrant testing (PT) of the CRDRL nozzle blend radius and bore regions and the reactor vessel wall area beneath the nozzle, return-flow-capacity demonstration, CRD-system-performance testing and ultrasonic inspection of welded connections in the rerouted line. The inspection is to include base metal to a distance of one-pipe-wall thickness or 0.5 in., whichever is greater, on both sides of the weld.

5. ***Monitoring and Trending:*** The inspection schedule of NUREG-0619 provides timely detection of cracks.

6. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500. All cracks found in the CRDRL nozzles are to be removed by grinding.

7. ***Corrective Actions:*** Repair is in conformance with IWB-4000 and replacement in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Cracking has occurred in several BWR plants (NUREG-0619). The present AMP has been implemented for nearly 20 years and found to be effective in managing the effect of cracking on the intended function of CRDRL nozzles.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*, U.S. Nuclear Regulatory Commission, November 1980.

XI.M7 BWR STRESS CORROSION CRACKING

Program Description

The program to manage intergranular stress corrosion cracking (IGSCC) in boiling water reactor (BWR) coolant pressure boundary piping made of stainless steel (SS) is delineated in NUREG-0313, Rev. 2, and Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 and its Supplement 1. The program includes (a) preventive measures to mitigate IGSCC, and (b) inspection and flaw evaluation to monitor IGSCC and its effects. The staff-approved boiling water reactor vessel and internals project (BWRVIP)-75 report allows for modifications of inspection scope in the GL 88-01 program.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program focuses on (a) managing and implementing countermeasures to mitigate IGSCC and (b) performing inservice inspection (ISI) to monitor IGSCC and its effects on the intended function of BWR components. The program is applicable to all BWR piping made of austenitic SS that is 4 in. or larger in nominal diameter and contains reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification. The program also applies to pump casings, valve bodies and reactor vessel attachments and appurtenances, such as head spray and vent components. NUREG-0313 and NRC GL-88-01, respectively, describe the technical basis and staff guidance regarding mitigation of IGSCC in BWRs. Attachment A of NRC GL 88-01 delineates the staff-approved positions regarding materials, processes, water chemistry, weld overlay reinforcement, partial replacement, stress improvement of cracked welds, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

2. ***Preventive Actions:*** The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause IGSCC. These elements consist of a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic SSs containing greater than 0.03 wt.% carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates an envelope of chromium depleted region that, in certain environments, is susceptible to stress corrosion cracking (SCC). Residual tensile stresses are introduced from fabrication processes, such as welding, surface grinding, or forming. High levels of dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes.

   The program delineated in NUREG-0313 and NRC GL 88-01 and in the staff-approved BWRVIP-75 report includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered to be resistant to SCC; other nickel-alloys, such as Alloy 600 are evaluated on an individual basis. Special processes are used for existing, new, and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

The program delineated in NUREG-0313 and NRC GL 88-01 does not provide specific guidelines for controlling reactor water chemistry to mitigate IGSCC. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (Electric Power Research Institute [EPRI] TR-103515). The program description, and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Section XI.M2, "Water Chemistry."

3. ***Parameters Monitored/Inspected:*** The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in NUREG 0313, Rev. 2, and NRC GL 88-01 or the referenced BWRVIP-75 guideline as approved by the NRC staff.

4. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 or BWRVIP-75 are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. The program uses volumetric examinations to detect IGSCC.

   The NRC GL 88-01 recommends that the detailed inspection procedure, equipment, and examination personnel be qualified by a formal program approved by the NRC. These inspection guidelines, updated in the approved BWRVIP-75 document, provide the technical basis for revisions to NRC GL 88-01 inspection schedules. Inspection can reveal crack initiation and growth and leakage of coolant. The extent and frequency of inspection recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce residual stresses, and how the weld was repaired if it had been cracked). The inspection guidance in approved BWRVIP-75 replaces the extent and schedule of inspection in NRC GL 88-01.

5. ***Monitoring and Trending:*** The extent and schedule for inspection, in accordance with the recommendations of NRC GL 88-01 or approved BWRVIP-75 guidelines, provide timely detection of cracks and leakage of coolant. Based on inspection results, NRC GL 88-01 or approved BWRVIP-75 guidelines provide guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.

6. ***Acceptance Criteria:*** As recommended in NRC GL 88-01, any indication detected is evaluated in accordance with the ASME Section XI, Subsection IWB-3640 (1995 edition through the 1996 addenda) and the guidelines of NUREG-0313.

   Applicable and approved BWRVIP-14, BWRVIP-59, BWRVIP-60, and BWRVIP-62 documents provide guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 guidelines for BWR vessel and internals induction heating stress improvement effectiveness on crack growth in operating plants.

7. ***Corrective Actions***: The guidance for weld overlay repair and stress improvement or replacement is provided in NRC GL 88-01; ASME Section XI, Subsections IWB-4000 and IWB-7000, IWC-4000 and IWC-7000, or IWD-4000 and IWD-7000, respectively for Class 1, 2, or 3 components; and ASME Code Case N 504-1. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Intergranular stress corrosion cracking has occurred in small- and large-diameter BWR piping made of austenitic stainless steel and nickel-base alloys. Cracking has occurred in recirculation, core spray, residual heat removal (RHR), and reactor water cleanup (RWCU) system piping welds (NRC GL 88-01, NRC Information Notices [INs] 82-39 and 84-41). The comprehensive program outlined in NRC GL 88-01 and NUREG-0313 and in the staff-approved BWRVIP-75 report addresses mitigating measures for SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment). The GL 88-01 program has been effective in managing IGSCC in BWR reactor coolant pressure-retaining components and the revision to the GL 88-01 program, according to the staff-approved BWRVIP-75 report, will adequately manage IGSCC degradation.

References

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Code Case N-504-1, *Alternative Rules for Repair of Class 1, 2, and 3 Austenitic Stainless Steel Piping,* Section XI, Division 1, 1995 Edition, ASME Boiler and Pressure Vessel Code – Code Cases – Nuclear Components, American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-14, *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, (EPRI TR-105873, July 11, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-14, December 3, 1999.

BWRVIP-29 (EPRI TR-103515), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry,* Electric Power Research Institute, Palo Alto, CA, February 1994.

BWRVIP-59, *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals, (EPRI TR-108710),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-60, *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals, (EPRI TR-108709, April 14, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-61, *BWR Vessel and Internals Induction Heating Stress Improvement Effectiveness on Crack Growth in Operating Reactors, (EPRI TR-112076),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, January 29, 1999.

BWRVIP-62, *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection, (EPRI TR-108705),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-75, *Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313), (EPRI TR-113932, Feb. 29, 2000),* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-75, September 15, 2000.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,* U.S. Nuclear Regulatory Commission, January 25, 1988; Supplement 1, February 4, 1992.

NRC Information Notice 82-39, *Service Degradation of Thick Wall Stainless Steel Recirculation System Piping at a BWR Plant,* U.S. Nuclear Regulatory Commission, September 21, 1982.

NRC Information Notice 84-41, *IGSCC in BWR Plants,* U.S. Nuclear Regulatory Commission, June 1, 1984.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping,* W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

XI.M8 BWR PENETRATIONS

Program Description

The program includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP)-49 and BWRVIP-27 documents and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-29 (Electric Power Research Institute [EPRI] TR-103515) to ensure the long-term integrity and safe operation of boiling water reactor (BWR) vessel internal components. The BWRVIP-49 provides guidelines for instrument penetrations, and BWRVIP-27 addresses the standby liquid control (SLC) system nozzle or housing.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the effects of crack initiation and growth due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC). The program contains preventive measures to mitigate SCC or IGSCC, inservice inspection (ISI) to monitor the effects of cracking on the intended function of the components, and repair and/or replacement as needed to maintain the ability to perform the intended function.

   The inspection and evaluation guidelines of BWRVIP-49 and BWRVIP-27 contain generic guidelines intended to present appropriate inspection recommendations to assure safety function integrity. The guidelines of BWRVIP-49 provide information on the type of instrument penetration, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. The guidelines of BWRVIP-27 are applicable to plants in which the SLC system injects sodium pentaborate into the bottom head region of the vessel (in most plants, as a pipe within a pipe of the core plate ΔP monitoring system). The BWRVIP-27 guidelines address the region where the ΔP and SLC nozzle or housing penetrates the vessel bottom head and include the safe ends welded to the nozzle or housing. Guidelines for repair design criteria are provided in BWRVIP-57 for instrumentation penetrations and BWRVIP-53 for SLC line.

2. ***Preventive Actions:*** Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry".

3. ***Parameters Monitored/Inspected:*** The program monitors the effects of SCC/IGSCC on the intended function of the component by detection and sizing of cracks by ISI in accordance with the guidelines of approved BWRVIP-49 or BWRVIP-27 and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB 2500-1 (1995 edition through the 1996 addenda). An applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry.

4. ***Detection of Aging Effects:*** The evaluation guidelines of BWRVIP-49 and BWRVIP-27 recommend that the inspection requirements currently in ASME Section XI continue to be followed. The extent and schedule of the inspection and test techniques prescribed by the ASME Section XI program are designed to maintain structural integrity and ensure that

aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal crack initiation and growth and leakage of coolant. The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals and their implementation needs, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03.

Instrument penetrations and SLC system nozzles or housings are inspected in accordance with the requirements of ASME Section XI, Subsection IWB. Components are examined and tested as specified in Table IWB-2500-1, examination categories B-E for pressure-retaining partial penetration welds in vessel penetrations, B-D for full penetration nozzle-to-vessel welds, B-F for pressure-retaining dissimilar metal nozzle-to-safe end welds, or B-J for similar metal nozzle-to-safe end welds. In addition, these components are part of examination category B-P for pressure-retaining boundary. Further details for examination are described in Chapter XI.M1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD," of this report.

5. ***Monitoring and Trending:*** Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-48 or BWRVIP-27 provide timely detection of cracks. The scope of examination expansion and reinspection beyond the baseline inspection are required if flaws are detected.

6. ***Acceptance Criteria:*** Any indication detected is evaluated in accordance with ASME Section XI or other acceptable flaw evaluation criteria, such as the staff-approved BWRVIP-49 or BWRVIP-27 guidelines. Applicable and approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

7. ***Corrective Actions:*** Repair and replacement procedures in the staff-approved BWRVIP-57 and BWRVIP-53 are equivalent to those requirements in the ASME Section XI. Guidelines for repair design criteria are provided in BWRVIP-57 for instrumentation penetrations and BWRVIP-53 for standby liquid control line. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-48, as modified, will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with 10 CFR Part 50, Appendix B.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-48, as modified, will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with the 10 CFR Part 50, Appendix B, confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Cracking due to SCC or IGSCC has occurred in BWR components made of austenitic stainless steels and nickel alloys. The program guidelines are based on evaluation of available information, including BWR inspection data and information about the elements that cause IGSCC, to determine which locations may be susceptible to cracking. Implementation of the program provides reasonable assurance that crack initiation and growth will be adequately managed so the intended functions of the instrument

penetrations and SLC system nozzles or housings will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-03, *BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines, (EPRI TR-105696 R1, March 30, 1999),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-03, July 15, 1999.

BWRVIP-14, *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, (EPRI TR-105873, July 11, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-14, December 3, 1999.

BWRVIP-27, *BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate P Inspection and Flaw Evaluation Guidelines, (EPRI TR-107286, April 1997),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-27 for Compliance with the License Renewal Rule (10 CFR Part 54), December 20, 1999.

BWRVIP-29 (EPRI TR-103515), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines–1993 Revision, Normal and Hydrogen Water Chemistry,* Electric Power Research Institute, Palo Alto, CA, February 1994.

BWRVIP-48, *BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines, (EPRI TR-108724, February 1998),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-48 for Compliance with the License Renewal Rule (10 CFR Part 54), January 17, 2001.

BWRVIP-49, *BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines, (EPRI TR-108695, March 1998),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-49 for Compliance with the License Renewal Rule (10 CFR Part 54), September 1, 1999.

BWRVIP-53, *BWR Vessel and Internals Project, Standby Liquid Control Line Repair Design Criteria, (EPRI TR-108716, March 24, 2000),* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-53, October 26, 2000.

BWRVIP-57, *BWR Vessel and Internals Project, Instrument Penetration Repair Design Criteria, (EPRI TR-108721),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-59, *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals, (EPRI TR-108710),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-60, *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals, (EPRI TR-108709, April 14, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-62, *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection, (EPRI TR-108705),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

XI.M9 BWR VESSEL INTERNALS

Program Description

The program includes (a) inspection and flaw evaluation in conformance with the guidelines of applicable and staff-approved boiling water reactor vessel and internals project (BWRVIP) documents and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-29 (Electric Power Research Institute [EPRI] TR-103515) to ensure the long-term integrity and safe operation of boiling water reactor (BWR) vessel internal components.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the effects of crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC). The program contains preventive measures to mitigate SCC, IGSCC, or IASCC; inservice inspection (ISI) to monitor the effects of cracking on the intended function of the components; and repair and/or replacement as needed to maintain the ability to perform the intended function.

   The BWRVIP documents provide generic guidelines intended to present the applicable inspection recommendations to assure safety function integrity of the subject safety-related reactor pressure vessel internal components. The guidelines include information on component description and function; evaluate susceptible locations and safety consequences of failure; provide recommendations for methods, extent, and frequency of inspection; discuss acceptable methods for evaluating the structural integrity significance of flaws detected during these examinations; and recommend repair and replacement procedures.

   The various applicable BWRVIP guidelines are as follows:

   Core shroud: BWRVIPs-07, -63, and -76 provide guidelines for inspection and evaluation; BWRVIP-02, Rev. 2, provides guidelines for repair design criteria.

   Core plate: BWRVIP-25 provides guidelines for inspection and evaluation; BWRVIP-50 provides guidelines for repair design criteria.

   Shroud support: BWRVIP-38, provides guidelines for inspection and evaluation; BWRVIP-52 provides guidelines for repair design criteria.

   Low-pressure coolant injection (LPCI) coupling: BWRVIP-42 provides guidelines for inspection and evaluation; BWRVIP-56 provides guidelines for repair design criteria.

   Top guide: BWRVIP-26 provides guidelines for inspection and evaluation; BWRVIP-50 provides guidelines for repair design criteria.

   Core spray: BWRVIP-18 provides guidelines for inspection and evaluation; BWRVIP-16 and 19 provides guidelines for replacement and repair design criteria, respectively.

   Jet pump assembly: BWRVIP-41 provides guidelines for inspection and evaluation; BWRVIP-51 provides guidelines for repair design criteria.

Control rod drive (CRD) housing: BWRVIP-47 provides guidelines for inspection and evaluation; BWRVIP-58 provides guidelines for repair design criteria.

Lower plenum: BWRVIP-47 provides guidelines for inspection and evaluation; BWRVIP-57 provides guidelines for repair design criteria for instrument penetrations.

In addition, BWRVIP-44 provides guidelines for weld repair of nickel alloys; BWRVIP-45 provides guidelines for weldability of irradiated structural components.

2. ***Preventive Actions:*** Maintaining high water purity reduces susceptibility to cracking due to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and evaluation, and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

3. ***Parameters Monitored/Inspected:*** The program monitors the effects of cracking on the intended function of the component by detection and sizing of cracks by inspection in accordance with the guidelines of applicable and approved BWRVIP documents and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB 2500-1 (1995 edition through the 1996 addenda). An applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the applicable and approved BWRVIP guidelines are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function. Inspection can reveal crack initiation and growth. Vessel internal components are inspected in accordance with the requirements of ASME Section XI, Subsection IWB, examination category B-N-2. The ASME Section XI inspection specifies visual VT-1 examination to detect discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surfaces of components. This inspection also specifies visual VT-3 examination to determine the general mechanical and structural condition of the component supports by (a) verifying parameters, such as clearances, settings, and physical displacements, and (b) detecting discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion.

   The applicable and approved BWRVIP guidelines recommend more stringent inspections, such as enhanced visual VT-1 examinations or ultrasonic methods of volumetric inspection, for certain selected components and locations. The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals and their implementation needs, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03.

5. ***Monitoring and Trending:*** Inspections scheduled in accordance with the applicable and approved BWRVIP guidelines provide timely detection of cracks. The scope of examination expansion and reinspection beyond the baseline inspection are required if flaws are detected.

6. ***Acceptance Criteria:*** Any indication detected is evaluated in accordance with ASME Section XI or the applicable staff-approved BWRVIP guidelines. Approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

7. ***Corrective Actions:*** Repair and replacement procedures are equivalent to those requirements in ASME Section XI. Repair and replacement is in conformance with the applicable and approved BWRVIP guidelines listed above. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in the staff-approved BWRVIP reports will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with 10 CFR Part 50, Appendix B.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in the staff-approved BWRVIP reports will provide an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with the 10 CFR Part 50, Appendix B, confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Extensive cracking has been observed in core shrouds at both horizontal (Nuclear Regulatory Commission [NRC] Generic Letter [GL] 94-03) and vertical (NRC Information Notice [IN] 97-17) welds. It has affected shrouds fabricated from Type 304 and Type 304L SS, which is generally considered to be more resistant to SCC. Weld regions are most susceptible, although it is not clear whether this is due to sensitization and/or impurities associated with the welds or the high residual stresses in the weld regions. This experience is reviewed in NRC GL 94-03 and NUREG-1544; some experiences with visual inspections are discussed in NRC IN 94-42.

    Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) has been observed in the shroud support access hole cover made from Alloy 600. Instances of cracking in core spray spargers have been reviewed in NRC IE Bulletin 80-13.

    Cracking of the core plate has not been reported, but the creviced regions beneath the plate are difficult to inspect. The NRC IN 95-17 discusses cracking in top guides of United States and overseas BWRs. Related experience in other components is reviewed in NRC GL 94-03 and NUREG-1544. Cracking has also been observed in the top guide of a Swedish BWR.

    Instances of cracking have occurred in the jet pump assembly (NRC IE Bulletin 80-07), hold-down beam (NRC IN 93-101), and jet pump riser pipe elbows (NRC IN 97-02).

    Cracking of dry tubes has been observed at 14 or more BWRs. The cracking is intergranular and has been observed in dry tubes without apparent sensitization, suggesting that IASCC may also play a role in the cracking.

    The program guidelines outlined in applicable and approved BWRVIP documents are based on evaluation of available information, including BWR inspection data and information on the elements that cause SCC, IGSCC, or IASCC, to determine which components may be susceptible to cracking. Implementation of the program provides reasonable assurance that crack initiation and growth will be adequately managed so the intended functions of the vessel internal components will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-02, *BWR Vessel and Internals Project, BWR Core Shroud Repair Design Criteria, Rev. 2,* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-03, *BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines, (EPRI TR-105696 R1, March 30, 1999),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-03, July 15, 1999.

BWRVIP-07, *BWR Vessel and Internals Project, Guidelines for Reinspection of BWR Core Shrouds, (EPRI TR-105747, Feb. 29, 1996),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-07, April 27, 1998.

BWRVIP-14, *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals, (EPRI TR-105873, July 11, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-14, December 3, 1999.

BWRVIP-16, *Internal Core Spray Piping and Sparger Replacement Design Criteria, (EPRI TR-106708),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-18, *BWR Vessel and Internals Project, BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines, (EPRI TR-106740, July 1996),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-18 for Compliance with the License Renewal Rule (10 CFR Part 54), December 7, 2000.

BWRVIP-19, *Internal Core Spray Piping and Sparger Repair Design Criteria, (EPRI TR 106893),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-25, *BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines, (EPRI TR-107284, Dec. 1996),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-25 for Compliance with the License Renewal Rule (10 CFR Part 54), December 7, 2000.

BWRVIP-26, *BWR Vessel and Internals Project, Top Guide Inspection and Flaw Evaluation Guidelines, (EPRI TR-107285, Dec. 1996),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-26 for Compliance with the License Renewal Rule (10 CFR Part 54), December 7, 2000.

BWRVIP-29, *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines–1993 Revision, Normal and Hydrogen Water Chemistry, (EPRI TR-103515),* Electric Power Research Institute, Palo Alto, CA, February 1994.

BWRVIP-38, *BWR Vessel and Internals Project, BWR Shroud Support Inspection and Flaw Evaluation Guidelines, (EPRI TR-108823, September 1997),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-38 for Compliance with the License Renewal Rule (10 CFR Part 54), March 1, 2001.

BWRVIP-41, *BWR Vessel and Internals Project, BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines, (EPRI TR-108728, October 1997),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-41 for Compliance with the License Renewal Rule (10 CFR Part 54), June 15, 2001.

BWRVIP-42, *BWR Vessel and Internals Project, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines, (EPRI TR-108726, December 1997),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-42 for Compliance with the License Renewal Rule (10 CFR Part 54), January 9, 2001.

BWRVIP-44, *Underwater Weld Repair of Nickel Alloy Reactor Vessel Internals, (EPRI TR-108708, April 3, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-44, June 9, 1999.

BWRVIP-45, *Weldability of Irradiated LWR Structural Components, (EPRI TR-108707),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, June 14, 2000.

BWRVIP-47, *BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines, (EPRI TR-108727, December 1997),* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-47 for Compliance with the License Renewal Rule (10 CFR Part 54), December 7, 2000.

BWRVIP-50, *Top Guide/Core Plate Repair Design Criteria, (EPRI TR-108722),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, April 3, 2000.

BWRVIP-51, *Jet Pump Repair Design Criteria, (EPRI TR-108718, March 7, 2000),* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-51, October 28, 2000.

BWRVIP-52, *Shroud Support and Vessel Bracket Repair Design Criteria, (EPRI TR-108720, June 26, 1998),* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-52, November 2, 2000.

BWRVIP-56, *LPCI Coupling Repair Design Criteria, (EPRI TR-108717),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-57, *Instrument Penetration Repair Design Criteria, (EPRI TR-108721),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-58, *CRD Internal Access Weld Repair, (EPRI TR-108703),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-59, *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals, (EPRI TR-108710),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 24, 2000.

BWRVIP-60, *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals, (EPRI TR-108709, April 14, 2000),* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-62, *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection, (EPRI TR-108705),* BWRVIP and Electric Power Research Institute, Palo Alto, CA, March 7, 2000.

BWRVIP-63, *BWR Vessel and Internals Project, Shroud Vertical Weld Inspection and Evaluation Guidelines, (EPRI TR-113117, Feb. 29, 2000),* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-63, April 18, 2000.

BWRVIP-76, *BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines, (EPRI TR-114232, November 1999).*

NRC Generic Letter 94-03, *Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors*, U.S. Nuclear Regulatory Commission, July 25, 1994.

NRC IE Bulletin No. 80-07, *BWR Jet Pump Assembly Failure*, U.S. Nuclear Regulatory Commission, April 4, 1980.

NRC IE Bulletin No. 80-13, *Cracking in Core Spray Spargers*, U.S. Nuclear Regulatory Commission, May 12, 1980.

NRC IE Bulletin No. 80-07, Supplement 1, *BWR Jet Pump Assembly Failure,* U.S. Nuclear Regulatory Commission, May 13, 1980.

NRC Information Notice 88-03, *Cracks in Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, February 2, 1988.

NRC Information Notice 92-57, *Radial Cracking of Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, August 11, 1992.

NRC Information Notice 93-101, *Jet Pump Hold-Down Beam Failure*, U.S. Nuclear Regulatory Commission, December 17, 1993.

NRC Information Notice 94-42, *Cracking in the Lower Region of the Core Shroud in Boiling Water Reactors*, U.S. Nuclear Regulatory Commission, June 7, 1994.

NRC Information Notice 95-17, *Reactor Vessel Top Guide and Core Plate Cracking*, U.S. Nuclear Regulatory Commission, March 10, 1995.

NRC Information Notice 97-02, *Cracks Found in Jet Pump Riser Assembly Elbows at Boiling Water Reactors*, U.S. Nuclear Regulatory Commission, February 6, 1997.

NRC Information Notice 97-17, *Cracking of Vertical Welds in the Core Shroud and Degraded Repair*, U.S. Nuclear Regulatory Commission, April 4, 1997.

NUREG-1544, *Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components*, U.S. Nuclear Regulatory Commission, March 1996.

XI.M10 BORIC ACID CORROSION

Program Description

The program relies on implementation of recommendations of Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-05 to monitor the condition of the reactor coolant pressure boundary for borated water leakage. Periodic visual inspection of adjacent structures, components, and supports for evidence of leakage and corrosion is an element of the NRC GL 88-05 monitoring program.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program covers any carbon steel and low-alloy steel structures or components, and electrical components, on which borated reactor water may leak. The program includes recommendations of NRC GL 88-05. The staff guidance of NRC GL 88-05 provides a program consisting of systematic measures to ensure that corrosion caused by leaking borated coolant does not lead to degradation of the leakage source or adjacent structures and components, and provides assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. Such a program provides for (a) determination of the principal location of leakage, (b) examination requirements and procedures for locating small leaks, and (c) engineering evaluations and corrective actions to ensure that boric acid corrosion does not lead to degradation of the leakage source or adjacent structures or components, which could cause the loss of intended function of the structures or components.

2. ***Preventive Actions:*** Minimizing reactor coolant leakage by frequent monitoring of the locations where potential leakage could occur, and timely repair if leakage is detected, prevents or mitigates boric acid corrosion. Preventive measures also include modifications in the design or operating procedures to reduce the probability of leaks at locations where they may cause corrosion damage and use of suitable corrosion resistant materials or the application of protective coatings.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors the effects of boric acid corrosion on the intended function of an affected structure and component by detection of coolant leakage. Coolant leakage results in deposits of white boric acid crystals and presence of moisture that can be observed by the naked eye.

4. ***Detection of Aging Effects:*** Degradation of the component due to boric acid corrosion cannot occur without leakage of coolant that contains boric acid. Conditions leading to boric acid corrosion, such as crystal buildup and evidence of moisture, are readily detectable by visual inspection. The program delineated in NRC GL 88-05 includes guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. Thus the use of the NRC GL 88-05 program will assure detection of leakage before the loss of the intended function of the component.

5. ***Monitoring and Trending:*** The program delineated in NRC GL 88-05 provides for timely detection of leakage by observance of boric acid crystals during normal plant walkdowns and maintenance.

6. ***Acceptance Criteria:*** Any detected leakage or crystal buildup requires corrective actions prior to continued service.

7. ***Corrective Actions*:** The leakage source and areas of general corrosion are located and corrective actions are implemented in conformance with the program proposed by NRC GL 88-05. The NRC GL 88-05 requires that corrective actions to prevent recurrences of degradation caused by boric acid leakage be included in the program implementation. These corrective actions include any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of primary coolant leaks at locations where they may cause corrosion damage, and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings or claddings. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Boric acid corrosion observed in nuclear power plants (NRC Information Notice [IN] 86-108 S3) may be classified into two types: (a) corrosion that increases the rate of leakage (e.g., corrosion of closure bolting or fasteners) and (b) corrosion that occurs some distance from the source of leakage. The guidance of NRC GL 88-05 is effective in managing the effects of boric acid corrosion on the intended function of reactor components.

References

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

NRC Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, U.S. Nuclear Regulatory Commission, March 17, 1988.

NRC Information Notice 86-108 S3, *Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion*, U.S. Nuclear Regulatory Commission, December 26, 1986; Supplement 1, April 20, 1987; Supplement 2, November 19, 1987; and Supplement 3, January 5, 1995.

XI.M11 NICKEL-ALLOY NOZZLES AND PENETRATIONS

Program Description

The program includes (a) primary water stress corrosion cracking (PWSCC) susceptibility assessment to identify susceptible components, (b) monitoring and control of reactor coolant water chemistry to mitigate PWSCC, and (c) inservice inspection (ISI) of reactor vessel head penetrations in accordance with the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, Table IWB 2500-1 (1995 edition through the 1996 addenda) to monitor PWSCC and its effect on the intended function of the component. For susceptible penetrations and locations, the program includes an industry-wide, integrated, long-term inspection program based on the industry responses to NRC Generic Letter (GL) 97-01 contained in the NEI letter dated December 11, 1998, from Dave Modeen to Gus Lainas, "Responses to NRC Requests for Additional Information (RAIs) on GL 97-01" and individual plant responses. Primary water chemistry is monitored and maintained in accordance with the Electric Power Research Institute (EPRI) guidelines in TR-105714 (Rev. 3, or later revisions or update) to minimize the potential of crack initiation and growth.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the effects of crack initiation and growth due to primary water stress corrosion cracking (PWSCC) of nickel-base alloys. The program includes ISI in accordance with ASME Subsection IWB, Table IWB 2500-1. For susceptible components and locations, the program includes an industry wide, integrated, long-term inspection program based on the industry responses to NRC GL 97-01 contained in the NEI letter dated December 11, 1998, from Dave Modeen to Gus Lainas, "Responses to NRC Requests for Additional Information (RAIs) on GL 97-01" and individual plant responses. Preventive measures are in accordance with EPRI guidelines in TR-105714 to mitigate PWSCC. An integrated cracking susceptibility assessment in accordance with industry susceptibility models and inspection results was performed in response to NRC GL 97-01, to define the most susceptible plants and rank them in accordance with their susceptibility. The information is used by each plant to determine the proper timing of vessel head penetration examinations, either during the current license period or the period of license renewal, if necessary. The components and locations to be included in the long-term inspection program are those that currently have been identified as susceptible to PWSCC, and those that will become susceptible during the period of license renewal. Significant changes in the industry models, as future plants perform inspection, may require reassessment.

2. ***Preventive Actions:*** Preventive measures to mitigate PWSCC are in accordance with EPRI guidelines in TR-105714. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

3. ***Parameters Monitored/Inspected:*** The program monitors the effects of PWSCC on the intended function of the control rod drive (CRD) and other Alloy 600 head penetrations by detection and sizing of cracks and coolant leakage by ISI. In C-E-designed pressurized water reactors (PWRs), the CRD head penetration is called the control element drive (CED) head penetration.

4. ***Detection of Aging Effects:*** A review of the scope and schedule of the inspections, including the leakage detection system, based on NRC GL 97-01, assures detection of cracks before the loss of intended function of the components.

   The PWSCC susceptibility assessment was performed in response to NRC GL 97-01 utilizing the most current industry susceptibility models that were based on material and operating parameters and inspection results to date, to rank plants in accordance with their susceptibility. This information is used to develop a plant-specific long-term inspection program, including schedule, scope and determination whether an augmented inspection program of nozzle penetration, including a combination of surface and volumetric examination, is necessary. Because the leakage through cracks in nozzles can be small, this aging management program (AMP), in accordance with NRC GL 97-01, recommends implementation of an enhanced leakage detection method for detecting small leaks during plant operation.

5. ***Monitoring and Trending:*** An inspection schedule, in accordance with the integrated inspection program based on the NRC GL 97-01 susceptibility assessment, provides timely detection of cracks. Inspection results are used to update the susceptibility models. The frequency of subsequent inspections is based on the finding of the initial inspections and flaw evaluations performed with staff-approved crack growth rate models for nickel-alloys.

6. ***Acceptance Criteria:*** Any indication detected is evaluated in accordance with ASME Section XI or other acceptable flaw evaluation criteria. To verify the adequacy of the long-term inspection program and acceptance criteria, if there have been significant changes since the applicants response to NRC GL 97-01, the applicant either provides references to appropriate industry model revisions or provides updated information on crack initiation and crack growth data and models.

7. ***Corrective Actions:*** Repair and replacement procedures are equivalent to those requirements in ASME Section XI. Repair is in conformance with IWB-4000 and replacement is in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Cracking of Alloy 600 has occurred in domestic and foreign PWRs (NRC Information Notice [IN] 90-10). Furthermore, ingress of demineralizer resins has also occurred in operating plants (NRC IN 96-11), the program relies upon monitoring and control of primary water chemistry to manage the effects of such excursions. An integrated susceptibility assessment and inspection program, based on the guidelines in NRC GL 97-01, is effective in managing the effect of PWSCC on the intended function of reactor vessel head penetrations.

References

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

EPRI TR-105714, *PWR Primary Water Chemistry Guidelines–Revision 3,* Electric Power Research Institute, Palo Alto, CA, November 1995.

Letter from David J. Modeen of Nuclear Energy Institute to Gus C. Lainais of Division of Engineering, *Responses to NRC Requests for Additional Information on Generic Letter 97-01,* December 11, 1998.

NRC Generic Letter 97-01, *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,* U.S. Nuclear Regulatory Commission, April 1, 1997.

NRC Information Notice 90-10, *Primary Water Stress Corrosion Cracking (PWSCC) of Alloy 600,* U.S. Nuclear Regulatory Commission, February 23, 1990.

NRC Information Notice 96-11, *Ingress of Demineralizer Resins Increase Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations,* U.S. Nuclear Regulatory Commission, February 14, 1996.

XI.M12 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

Program Description

The reactor coolant system components are inspected in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. This inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) components. This aging management program (AMP) includes (a) determination of the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite, and (b) for "potentially susceptible" components, as defined below, aging management is accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI), screening for susceptibility to thermal aging is not required. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes screening criteria to determine which CASS components are potentially susceptible to thermal aging embrittlement and require augmented inspection. The screening criteria are applicable to all primary pressure boundary and reactor vessel internal components constructed from SA-351 Grades CF3, CF3A, CF8, CF8A, CF3M, CF3MA, CF8M, with service conditions above 250°C (482°F). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis. For potentially susceptible components, aging management is accomplished either through volumetric examination or plant- or component-specific flaw tolerance evaluation.

   Based on the criteria set forth in the May 19, 2000, NRC letter, the susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content (0.5 wt.% max.) steels, only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with ≤20% ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with ≤14% ferrite and centrifugal-cast high-molybdenum steels with ≤20% ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). A fracture toughness value of 255 kJ/m^2 (1,450 $in.\text{-}lb/in.^2$) at a crack depth of 2.5 mm (0.1 in.) is used to differentiate between CASS materials that are nonsusceptible and potentially susceptible to thermal aging embrittlement. Extensive research data indicate that for nonsusceptible CASS materials, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR-4513, Rev. 1).

For pump casings and valve bodies, screening for susceptibility to thermal aging embrittlement is not required. The staff's conservative bounding integrity analysis shows that thermally aged CASS valve bodies and pump casings are resistant to failure. For all pump casings and valve bodies greater than nominal pipe size (NPS) 4 in., the existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate. The ASME Section XI, Subsection IWB, requires only surface examination of valve bodies less than NPS 4 in. For valve bodies less than NPS 4 in., the adequacy of inservice inspection (ISI) according to ASME Section XI has been demonstrated by a NRC-performed bounding integrity analysis (see letter from Christopher Grimes).

2. ***Preventive Actions:*** The program consists of evaluation and inspection and provides no guidance on methods to mitigate thermal aging embrittlement.

3. ***Parameters Monitored/Inspected:*** The AMP monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that are susceptible to thermal aging embrittlement. For potentially susceptible materials, the program consists of either enhanced volumetric examination to detect and size cracks or plant- or component-specific flaw tolerance evaluation. (Loss of fracture toughness is of consequence only if cracks exist.)

4. ***Detection of Aging Effects:*** For pump casings and valve bodies and "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. For "potentially susceptible" piping, because the base metal does not receive periodic inspection per ASME Section XI, the CASS AMP provides for volumetric examination of the base metal, with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examination methods that meet the criteria of the ASME Section XI, Appendix VIII, are acceptable. Alternatively, a plant- or component-specific flaw tolerance evaluation, using specific geometry and stress information, can be used to demonstrate that the thermally-embrittled material has adequate toughness.

5. ***Monitoring and Trending:*** Inspection schedules in accordance with IWB-2400 or IWC-2400 and reliable examination methods provide timely detection of cracks.

6. ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500 or IWC-3500. Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). Extensive research data indicate that the lower-bound fracture toughness of thermally aged CASS materials with up to 25% ferrite is similar to that for SAWs with up to 20% ferrite (Lee et al., 1997). Flaw evaluation for piping with >25% ferrite is performed on a case-by-case basis by using fracture toughness data provided by the applicant.

7. ***Corrective Actions:*** Repair is in conformance with IWA-4000 and IWB-4000 or IWC, and replacement is in accordance with IWA-7000 and IWB-7000 or IWC-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The proposed AMP was developed by using research data obtained on both laboratory-aged and service-aged materials. Based on this information, the effects of thermal aging embrittlement on the intended function of CASS components are effectively managed.

References

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

Lee, S., Kuo, P. T., Wichman, K., and Chopra, O., *Flaw Evaluation of Thermally Aged Cast Stainless Steel in Light-Water Reactor Applications*, Int. J. Pres. Ves. and Piping, 72, pp. 37-44, 1997.

Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components,* May 19, 2000.

NUREG/CR-4513, Rev. 1, *Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,* U.S. Nuclear Regulatory Commission, August 1994.

XI.M13 THERMAL AGING AND NEUTRON IRRADIATION EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

Program Description

The reactor vessel internals receive a visual inspection in accordance with the American Society of Mechanical Engineers (ASME) Code Section XI, Subsection IWB, Category B-N-3. This inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging, neutron irradiation embrittlement and void swelling of cast austenitic stainless steel (CASS) reactor vessel internals. This aging management program (AMP) includes (a) identification of susceptible components determined to be limiting from the standpoint of thermal aging susceptibility (i.e., ferrite and molybdenum contents, casting process, and operating temperature) and/or neutron irradiation embrittlement (neutron fluence), and (b) for each "potentially susceptible" component, aging management is accomplished through either a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed as part of the applicant's 10-year inservice inspection (ISI) program during the license renewal term, or a component-specific evaluation to determine its susceptibility to loss of fracture toughness.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program provides screening criteria to determine the susceptibility of CASS components to thermal aging on the basis of casting method, molybdenum content, and percent ferrite. The screening criteria are applicable to all primary pressure boundary and reactor vessel internal components constructed from SA-351 Grades CF3, CF3A, CF8, CF8A, CF3M, CF3MA, CF8M, with service conditions above 250°C (482°F). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis. For "potentially susceptible" components, the program provides for the consideration of the synergistic loss of fracture toughness due to neutron embrittlement and thermal aging embrittlement. For each such component, an applicant can implement either (a) a supplemental examination of the affected component as part of a 10-year ISI program during the license renewal term, or (b) a component-specific evaluation to determine the component's susceptibility to loss of fracture toughness.

   Based on the criteria set forth in the May 19, 2000, Nuclear Regulatory Commission (NRC) letter, the susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content (0.5 wt.% max.) steels, only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with ≤20% ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with ≤14% ferrite and centrifugal-cast high-molybdenum steels with ≤20% ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). A fracture toughness value of 255 kJ/m^2 (1,450 $in.\text{-}lb/in.^2$) at a crack depth of 2.5 mm (0.1 in.) is used to differentiate between CASS materials that are nonsusceptible and potentially susceptible to thermal aging embrittlement. Extensive research data indicate that for nonsusceptible CASS materials, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR-4513, Rev. 1).

2. ***Preventive Actions:*** The program consists of evaluation and inspection and provides no guidance on methods to mitigate thermal aging, neutron irradiation embrittlement or void swelling.

3. ***Parameters Monitored/Inspected:*** The program specifics depend on the neutron fluence and thermal embrittlement susceptibility of the component. The AMP monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that either have a neutron fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are determined to be susceptible to thermal aging embrittlement. For such materials, the program consists of either supplemental examination of the affected component based on the neutron fluence to which the component has been exposed, or component-specific evaluation to determine the component's susceptibility to loss of fracture toughness.

4. ***Detection of Aging Effects:*** For all CASS components that have a neutron fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are determined to be susceptible to thermal embrittlement, the 10-year ISI program during the renewal period includes a supplemental inspection covering portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility (i.e., ferrite and molybdenum contents, casting process, and operating temperature), neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions). The inspection technique is capable of detecting the critical flaw size with adequate margin. The critical flaw size is determined based on the service loading condition and service-degraded material properties. One example of a supplemental examination is enhancement of the visual VT-1 examination of Section XI IWA-2210. A description of such an enhanced visual VT-1 examination could include the ability to achieve a 0.0005-in. resolution, with the conditions (e.g., lighting and surface cleanliness) of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique. Alternatively, the applicant may perform a component-specific evaluation, including a mechanical loading assessment to determine the maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. If the loading is compressive or low enough (<5 ksi) to preclude fracture, then supplemental inspection of the component is not required. Failure to meet this criterion requires continued use of the supplemental inspection program. For each CASS component that has been subjected to a neutron fluence of less than 10^{17} n/cm^2 (E>1 MeV) and is potentially susceptible to thermal aging, the supplement inspection program applies; otherwise, the existing ASME Section XI inspection requirements are adequate if the components are not susceptible to thermal aging embrittlement.

5. ***Monitoring and Trending:*** Inspections scheduled in accordance with IWB-2400 and reliable examination methods provide timely detection of cracks.

6. ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). Extensive research data indicate that the lower-bound fracture toughness of thermally aged CASS materials with up to 25% ferrite is similar to that for SAWs with up to 20% ferrite (Lee et al., 1997). Flaw evaluation for CASS components with

>25% ferrite is performed on a case-by-case basis by using fracture toughness data provided by the applicant.

7. ***Corrective Actions:*** Repair is in conformance with IWA-4000 and IWB-4000, and replacement is in accordance with IWA-7000 and IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The proposed AMP was developed by using research data obtained on both laboratory-aged and service-aged materials. Based on this information, the effects of thermal aging embrittlement on the intended function of CASS components are effectively managed.

References

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

Lee, S., Kuo, P. T., Wichman, K., and Chopra, O., *Flaw Evaluation of Thermally Aged Cast Stainless Steel in Light-Water Reactor Applications*, Int. J. Pres. Ves. and Piping, 72, pp. 37-44, 1997.

Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components*, May 19, 2000.

NUREG/CR-4513, Rev. 1, *Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems*, U.S. Nuclear Regulatory Commission, August 1994.

XI.M14 LOOSE PART MONITORING

Program Description

The program relies on an inservice monitoring program to detect and monitor loose parts in light-water reactor (LWR) power plants. This inservice loose part monitoring (LPM) program is based on the recommendations from the American Society of Mechanical Engineers operation and maintenance standards and guides (ASME OM-S/G)-1997, Part 12, "Loose Part Monitoring in Light-Water Reactor Power Plants."

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes measures to monitor and detect metallic loose parts by using transient signals analysis on acoustic data generated due to loose parts impact. The program is applicable, but not necessarily limited to, the reactor vessel and primary coolant systems in pressurized water reactors (PWRs) and the reactor recirculation system in boiling water reactors (BWRs). The detection and monitoring system includes a set of accelerometers installed in the vicinity of regions where loose parts impact is likely to occur. The system incorporates the capability of automatic annunciation (audible and visual), audio monitoring, automatic and manual signal recording, and acoustic signal analysis/evaluation. Measures for personnel radiation exposure and safety are included as part of the requirements of the LPM system. The objective of the LPM program is to provide early indication of component degradation.

2. ***Preventive Actions:*** The aging management program (AMP) is a monitoring/detection program that provides early indication and detection of the onset of aging degradation. It does not rely on preventive actions.

3. ***Parameters Monitored/Inspected:*** The program relies on the use of transient acoustic signals to provide information on the occurrence of metallic loose part impact. Reactor coolant system (RCS) background noise may mask the noise generated due to loose part impact. These background noises may arise from sources such as coolant flow and mechanically and hydraulically generated vibrations. To differentiate loose part impact noise from background noise, ASME OM-S/G-1997, Part 12, recommends that the monitoring system sensitivity be set on the basis of the background noise and that maximum sensitivity be accomplished that is consistent with an acceptable false alarm rate arising from the background noise.

4. ***Detection of Aging Effects:*** Impact signals contain significant information on the size of the impacting object, the impact force and energy, and the composition and shape of both the component struck and the impacting object. In general, the magnitude of the impact signal increases with the impact mass and impact velocity. However, the frequency response increases with increasing velocity and decreasing mass. These data may be used to extract information on possible loose part impact and differentiation from background noise.

5. ***Monitoring and Trending:*** The impact signals, collected data, frequency, and characteristics are recorded, monitored, and evaluated to locate and identify the source and cause of the acoustic signals for the purpose of determining the need and urgency for a detailed inspection and examination of the suspected reactor vessel internals components. These activities are performed and associated personnel are qualified in accordance with

site controlled procedures and processes, as indicated by vendor, industry, or regulatory guidance documents.

6. ***Acceptance Criteria:*** The LPM alarms that suggest metallic impacts are further evaluated to verify LPM operability and to determine the location of the impact, the impact energy, and mass. Plant process data are reviewed for anomalous behavior, and diagnostic results are assessed by plant personnel.

7. ***Corrective Actions:*** If LPM diagnostics indicate the presence of loose parts, then corrective actions are taken. In some cases, the results of the diagnostic may indicate the signal is due to a change in the plant background characteristics and not due to the presence of loose parts. In such cases, the LPM alarm rates may in time become so high as to be unacceptable in practice. Adjustment of the alarm threshold (setpoints) is allowed. However, the reason for the change in background is to be investigated and understood, and the change is to be documented. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The loose part monitoring program is extensively and effectively used by the industry. The program has been developed and published as a standard in the ASME "Standards and Guides for Operation and Maintenance of Nuclear Power Plants," Part 12, an American National Standard. Part 12 was developed on the basis of knowledge gained from operating experience and research conducted since the Nuclear Regulatory Commission (NRC) issued Regulatory Guide (RG) 1.133 in May 1981.

References

ANSI S2.11-1969, *American National Standard for the Selection of Calibrations and Tests for Electrical Transducers Used for Monitoring Shock and Vibrations*, American National Standards Institute, Washington, DC, 1969.

ASME OM-S/G-1997, Part 12, *Loose Part Monitoring in Light-Water Reactor Power Plants*, American Society of Mechanical Engineers, New York, NY, 1997.

NRC Regulatory Guide 1.133, Rev. 1, *Loose Part Detection Program for the Primary System of Light Water Cooled Reactors*, U.S. Nuclear Regulatory Commission, 1981.

XI.M15 NEUTRON NOISE MONITORING

Program Description

The program relies on monitoring the excore neutron detector signals due to core motion to detect and monitor significant loss of axial preload at the core support barrel's upper support flange in pressurized water reactors (PWRs). This inservice monitoring program is based on the recommendations from the American Society of Mechanical Engineers operation and maintenance standards and guides (ASME OM-S/G)-1997, Part 5, "Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactors Power Plants."

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes measures to monitor and detect loss of axial preload (loss of axial restraint) at the core support barrel's upper support flange in PWRs. The loss of axial restraint may arise from long-term changes resulting from abnormal wear at the reactor vessel core barrel mating surface or short-term changes due to improper installation of the reactor internals. The program also includes guidelines for further data acquisition that may be needed to define future plant operation and/or program plans in order to maintain the capability of the structure/components to perform the intended function.

2. ***Preventive Actions:*** The aging management program (AMP) is a monitoring/detection program that provides early indication and detection of the onset of aging degradation of the core support barrel holddown mechanism prior to a scheduled shutdown, thus reducing outage time and avoiding potential damage to the core support barrel and fuel assemblies. The AMP does not rely on preventive actions.

3. ***Parameters Monitored/Inspected:*** The program relies on the use of excore neutron detector signals to provide information on the conditions of the axial preload. The excore neutron flux signal is composed of a steady state, direct current (DC), component that arises from the neutron flux produced by the power operation of the reactor, as well as a fluctuating (noise-like) component. This fluctuating signal arises from the core reactivity changes due to lateral core motion from the loss of axial preload. This core motion is mainly the result of beam mode vibration of the core support barrel. Despite the fact that this beam mode vibration provides only a very weak neutron noise source, it may be reliably detected and identified through Fourier Analysis of the fluctuating signal component of the excore neutron flux signal. This signal component has the characteristics of having 180-degree shifts and a high degree of coherence between signals obtained from pairs of excore neutron detectors that are positioned on diametrically opposite sides of the core. The neutron noise signals are characterized by parameters, which include the auto correlation, cross correlation, coherence, and phase. These parameters are to be monitored and evaluated.

4. ***Detection of Aging Effects:*** Flow-induced vibration of the core support barrel will change the thickness of the downcomer annulus (water gap). This variation in the thickness will give rise to fluctuating changes in the neutron flux, as monitored by the excore neutron detectors. The natural frequencies and the amplitudes of the vibratory motion of the core barrel are related to the effective axial preload at the upper support flange of the core support barrel. Monitoring of the neutron noise signal obtained with the neutron flux detectors located around the external periphery of the reactor vessel provides detection of anomalous vibrational motion of the core support barrel, and hence significant loss of the

axial preload. Decrease in the axial preload leads to decreases in the core support barrel beam mode frequency and an increase in the magnitude of the noise signal. The overall effect of a decrease in the axial preload is to shift the neutron noise power spectrum toward larger amplitudes for the lower frequency region.

5. ***Monitoring and Trending:*** The neutron noise random fluctuation in the signals from the excore detectors are monitored, recorded, and analyzed to identify changes in the beam mode natural frequency of the core support barrel and its direction of motion for the purpose of a timely determination of the need and urgency for a detailed inspection and examination of the reactor vessel internals hold-down mechanism and mating component surfaces. These activities and analytical methodology are performed and associated personnel are qualified in accordance with site-controlled procedures and processes as indicated by vendor, industry, or regulatory guidance documents.

   The neutron noise monitoring program has three separate phases: a baseline phase, a surveillance phase, and a diagnostic phase. The baseline phase establishes the database to be used as a reference for developing limits and trends in the surveillance phase and to support data evaluation and interpretation in the diagnostic phase. During the baseline phase, data on the time history and DC level of each neutron flux detector and each cross-core detector pair are obtained. From this database, the characteristic amplitudes and frequencies of the core barrel motion are extracted. The wide and narrow frequency bands with their associated normalized root mean square (NRMS) values are established. The ASME-OMS/G-1997, Part 5, recommends collecting the baseline data during the first fuel cycle that the neutron noise monitoring program is applied to an already operating plant. Whenever significant changes takes place for the core, reactor internals, or operating conditions, then additional baseline data is obtained.

   In the surveillance phase, routine neutron noise monitoring of normal plant operations is performed over the life of the plant. The DC level and data for frequency analysis of each detector and two pair of cross-core detectors, may be collected. Comparisons of the measured amplitude and frequency data, with limits established from the baseline data, are made. In using neutron noise monitoring, accounts are taken of the effect of core burn-up, decreasing boron concentration, changes in fuel management, and in-core contact with the reactor vessel mechanical snubbers, which may affect the neutron noise signatures. Proper allowances for these factors during the baseline and surveillance phases will help toward detecting loss of axial preload before the core barrel becomes sufficiently free to wear against the reactor vessel and will also reduce the need to invoke the diagnostic phase.

   If the diagnostic phase becomes necessary, then evaluations are carried out to establish whether any deviations from the baseline data detected during the surveillance phase arises from core barrel motion due to loss of axial preload. The need and frequency of additional data collection on the time history and DC level of each neutron flux detector and each cross-core detector pair collection are guided by the results of these evaluations.

6. ***Acceptance Criteria:*** If evaluation of the baseline data indicates normal operation for the applicable structure/component then the surveillance phase may commence. If evaluation indicates anomalous behavior, then the monitoring program enters the diagnostic phase. During the surveillance phase, if deviations from the baseline fall within predetermined acceptable limits, then the surveillance will continue. Otherwise, the diagnostic phase will commence.

7. ***Corrective Actions:*** Initial results from the diagnostic phase of the program may be used to determine whether there is a need to increase the minimum frequency with which the surveillance data are acquired. In addition, if necessary, corrective actions may be taken to change the type of data acquisition and analysis from that previously recommended for the surveillance part of the program. The data trends may be established to guide further data acquisition that may be needed to define future plant operation and/or program plans. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The neutron noise monitoring program and procedures were developed by the industry and published as a guide in ASME OM-S/G-1997, Part 5, an American National Standard. This monitoring program and procedures have been effective in limited industry use for monitoring and detecting loss of core support barrel axial preload in PWR power plants.

References

ASME OM-S/G-1997, Part 5, *Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants*, American Society of Mechanical Engineers, New York, NY, 1997.

XI.M16 PWR VESSEL INTERNALS

Program Description

The program includes (a) augmentation of the inservice inspection (ISI) in accordance with the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, Table IWB 2500-1 (1995 edition through the 1996 addenda) for certain susceptible or limiting components or locations, and (b) monitoring and control of reactor coolant water chemistry in accordance with the Electric Power Research Institute (EPRI) guidelines in TR-105714 to ensure the long-term integrity and safe operation of pressurized water reactor (PWR) vessel internal components. The ASME Section XI ISI is augmented with enhancing the VT-1 examinations for non-bolted components for example, to include the ability to achieve a 0.0005-inch resolution. The inspection methods for bolted components are to be demonstrated for detecting cracks between the bolt head and the shank.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the effects of crack initiation and growth due to stress corrosion cracking (SCC) or irradiation assisted stress corrosion cracking (IASCC), and loss of fracture toughness due to neutron irradiation embrittlement or void swelling. The program contains preventive measures to mitigate SCC or IASCC; ISI to monitor the effects of cracking on the intended function of the components; and repair and/or replacement as needed to maintain the ability to perform the intended function. Loss of fracture toughness is of consequence only if cracks exist. Cracking is expected to initiate at the surface and is detectable by augmented inspection.

   The program provides guidelines to assure safety function integrity of the subject safety-related reactor pressure vessel internal components, both non-bolted and bolted components. The program consists of the following elements: (a) identify the most susceptible or limiting items, (b) develop appropriate inspection techniques to permit detection and characterizing of the feature (cracks) of interest and demonstrate the effectiveness of the proposed technique, and (c) implement the inspection during the license renewal term. For example, appropriate inspection techniques may include enhancing visual VT-1 examinations for non-bolted components and demonstrated acceptable inspection methods for bolted components.

2. ***Preventive Actions:*** The requirements of ASME Section XI, Subsection IWB, provide guidance on detection, but do not provide guidance on methods to mitigate cracking. Maintaining high water purity reduces susceptibility to cracking due to SCC. Reactor coolant water chemistry is monitored and maintained in accordance with the EPRI guidelines in TR-105714. The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

3. ***Parameters Monitored/Inspected:*** The program monitors the effects of cracking on the intended function of the component by detection and sizing of cracks by augmentation of ISI in accordance with the requirements of the ASME Code, Section XI, Table IWB 2500-1.

4. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the aging management program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function. Inspection can reveal crack initiation and growth. Vessel internal components are inspected in accordance with the requirements of ASME Section XI, Subsection IWB,

examination category B-N-3 for all accessible surfaces of reactor core support structure that can be removed from the vessel. The ASME Section XI inspection specifies visual VT-3 examination to determine the general mechanical and structural condition of the component supports by (a) verifying parameters, such as clearances, settings, and physical displacements, and (b) detecting discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion.

However, visual VT-3 examination is to be augmented to detect tight or fine cracks. Also, historically the VT-3 examinations have not identified bolt cracking because cracking occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. Creviced and other inaccessible regions are difficult to inspect visually. This AMP recommends more stringent inspections such as enhanced visual VT-1 examinations or ultrasonic methods of volumetric inspection, for certain selected components and locations.

The inspection technique is capable of detecting the critical flaw size with adequate margin. The critical flaw size is determined based on the service loading condition and service-degraded material properties. For non-bolted components, augmented ISI may include enhancement of the visual VT-1 examination of Section XI IWA-2210. A description of such an enhanced visual VT-1 examination should include the ability to achieve a 0.0005-in. resolution, with the conditions (e.g., lighting and surface cleanliness) of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique. For bolted components, augmented ISI is to include other demonstrated acceptable inspection methods to detect cracks between the bolt head and the shank. Alternatively, the applicant may perform a component-specific evaluation, including a mechanical loading assessment to determine the maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. If the loading is compressive or low enough (<5 ksi) to preclude fracture, then supplemental inspection of the component is not required. Failure to meet this criterion requires continued use of the augmented inspection methods.

5. ***Monitoring and Trending:*** Inspection schedules in accordance with IWB-2400, assessment of susceptible or limiting components or locations, and reliable examination methods provide timely detection of cracks. The scope of examination expansion and re-inspection beyond the baseline inspection are required if flaws are detected.

6. ***Acceptance Criteria:*** Any indication or relevant condition of degradation is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

7. ***Corrective Actions:*** Repair and replacement procedures are equivalent to those requirements in ASME Section XI. Repair is in conformance with IWB-4000 and replacement occurs according to IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Because the ASME Code is a consensus document that has been widely used over a long period, it has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants.

In PWRs, stainless steel components have generally not been found to be affected by SCC because of low dissolved oxygen levels and control of primary water chemistry. However, the potential for SCC exists due to inadvertent introduction of contaminants into the primary coolant system from unacceptable levels of contaminants in the boric acid; introduction through the free surface of the spent fuel pool, which can be a natural collector of airborne contaminants (NRC IN 84-18); introduction of relatively high levels of oxygen during shutdown, or from aggressive chemistries that may develop in creviced regions. Cracking has occurred in SS baffle former bolts in a number of foreign plants (NRC IN 98-11) and has now been observed in plants in the United States.

References

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

EPRI TR-105714, *PWR primary Water Chemistry Guidelines-Revision 3,* Electric Power Research Institute, Palo Alto, CA, November 1995.

NRC Information Notice 84-18, *Stress Corrosion Cracking in PWR Systems,* March 7, 1984.

NRC Information Notice 98-11, *Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants,* March 25, 1998.

XI.M17 FLOW-ACCELERATED CORROSION

Program Description

The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective flow-accelerated corrosion (FAC) program. The program includes performing (a) an analysis to determine critical locations, (b) limited baseline inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.

Evaluation and Technical Basis

1. ***Scope of Program:*** The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as valve bodies, elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations; (b) performing limited baseline inspections to determine the extent of thinning at these locations; and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. The NSAC-202L-R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.

2. ***Preventive Actions:*** The FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAC.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors the effects of FAC on the intended function of piping and components by measuring wall thickness.

4. ***Detection of Aging Effects:*** Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic and radiographic testing is used to detect wall thinning. The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function.

5. ***Monitoring and Trending:*** CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions. CHECWORKS is acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides

reasonable assurance that structural integrity will be maintained between inspections. If degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning.

6. ***Acceptance Criteria:*** Inspection results are used as input to a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed thickness before the next scheduled outage, the component is to be repaired, replaced, or reevaluated.

7. ***Corrective Actions:*** Prior to service, reevaluate, repair, or replace components for which the acceptance criteria are not satisfied. Longer term corrective actions could consist of adjustment of operating parameters or selection of materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notices [INs] 81-28, 92-35, 95-11) and in two-phase piping in extraction steam lines (NRC INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (NRC INs 89-53, 91-18, 93-21, 97-84). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components.

References

NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning,* U.S. Nuclear Regulatory Commission, May 2, 1989.

NRC IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, July 9, 1987.

NRC Information Notice 81-28, *Failure of Rockwell-Edward Main Steam Isolation Valves,* U.S. Nuclear Regulatory Commission, September 3, 1981.

NRC Information Notice 89-53, *Rupture of Extraction Steam Line on High Pressure Turbine,* U.S. Nuclear Regulatory Commission, June 13, 1989.

NRC Information Notice 91-18, *High-Energy Piping Failures Caused by Wall Thinning,* U.S. Nuclear Regulatory Commission, March 12, 1991.

NRC Information Notice 91-18, Supplement 1, *High-Energy Piping Failures Caused by Wall Thinning,* U.S. Nuclear Regulatory Commission, December 18, 1991.

NRC Information Notice 92-35, *Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor*, U.S. Nuclear Regulatory Commission, May 6, 1992.

NRC Information Notice 93-21, *Summary of NRC Staff Observations Compiled during Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs*, U.S. Nuclear Regulatory Commission, March 25, 1993.

NRC Information Notice 95-11, *Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device*, U.S. Nuclear Regulatory Commission, February 24, 1995.

NRC Information Notice 97-84, *Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion*, U.S. Nuclear Regulatory Commission, December 11, 1997.

NSAC-202L-R2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, Electric Power Research Institute, Palo Alto, CA, April 8, 1999.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants*, P. C. Wu, U.S. Nuclear Regulatory Commission, April 1989.

XI.M18 BOLTING INTEGRITY

Program Description

The program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety related bolting. The program relies on industry recommendations for a comprehensive bolting maintenance, as delineated in the EPRI TR-104213 for pressure retaining bolting and structural bolting. The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program covers all bolting within the scope of license renewal including safety-related bolting, bolting for NSSS component supports, bolting for other pressure retaining components, and structural bolting. The program covers both greater than and smaller than 2-in. diameter bolting. The Nuclear Regulatory Commission (NRC) staff recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339. The industry's technical basis for the program for safety related bolting and guidelines for material selection and testing, bolting preload control, inservice inspection (ISI), plant operation and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG 1339. For other bolting, this information is set forth in EPRI TR-104213.

2. ***Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769 and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting (see item 10, below). (NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them.) Initial ISI of bolting for pressure retaining components includes a check of the bolt torque and uniformity of the gasket compression after assembly. It is noted that hot torquing of bolting is a leak preventive measure once the joint is brought to operating temperature and before or after it is pressurized. Hot torquing thus reestablishes preload before leak starts, but is ineffective in sealing a leak once it has begun.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors the effects of aging on the intended function of closure bolting, including loss of material, cracking, and loss of preload. High strength bolts (actual yield strength $\geq$ 150 ksi) used in NSSS component supports are monitored for cracking. Bolting for pressure retaining components is inspected for signs of leakage. Structural bolting is inspected for indication of potential problems including loss of coating integrity and obvious signs of corrosion, rust, etc.

4. ***Detection of Aging Effects:*** Inspection requirements are in accordance with the American Society of Mechanical Engineers (ASME) Section XI, Table IWB 2500-1 or IWC 2500-1 (1995 edition through the 1996 addenda) and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, examination category B-G-1, for bolting greater than 2 in. in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. All high strength bolting used in NSSS component supports are to be inspected also to the requirements for Class 1

components, examination category B-G-1. Examination category B-G-2, for bolting 2 in. or smaller requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, examination category B-D, for bolting greater than 2 in. in diameter, requires volumetric examination of studs and bolts. Examination categories B-P or C-H require visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1 and 2 components, according to Tables IWB 2500-1 and IWC 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with IWB 2500-1 or IWC 2500-1, assure detection of aging degradation before the loss of the intended function of the closure bolting. Structural bolting both inside and outside containment is inspected by visual inspection. Degradation of this bolting may be detected and measured either by removing the bolt, proof test by tension or torquing, by in situ ultrasonic tests, or hammer test. If this bolting is found corroded, a closer inspection is performed to assess extent of corrosion.

5. ***Monitoring and Trending:*** The inspection schedules of ASME Section XI are effective and ensure timely detection of cracks and leakage. If bolting for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to weekly or biweekly.

6. ***Acceptance Criteria:*** Any indications in closure bolting are evaluated in accordance with IWB-3100 and acceptance standards of IWB-3400 and IWB-3500, or IWC-3100 and acceptance standards of IWC-3400 and IWC-3500. Indications of cracking in component support bolting warrant immediate replacement of the cracked bolt. For other pressure retaining components, a leak from a joint is immediately repaired if it is a major leak and causes adverse effect such as corrosion or contamination.

7. ***Corrective Actions:*** Repair and replacement is in conformance with IWB-4000 and guidelines and recommendations of EPRI NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions. Repair and replacement of other bolting including structural bolting is in conformance with the guidelines and recommendations of EPRI TR-104213.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See item 8, above.

10. ***Operating Experience:*** Degradation of threaded fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, stress corrosion cracking, and fatigue loading (NRC IE Bulletin 82-02, NRC Generic Letter [GL] 91-17). Stress corrosion cracking has occurred in high strength bolts used for NSSS component supports. The bolting integrity programs developed and implemented in accordance with commitments made in response to NRC communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI NP-5769 and TR-104213 and represent industry consensus.

References

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, Palo Alto, CA, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric Power Research Institute, Palo Alto, CA, December 1995.

NRC Generic Letter 91-17, *Generic Safety Issue 79, "Bolting Degradation or Failure in Nuclear Power Plants,"* U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, Richard E. Johnson, U.S. Nuclear Regulatory Commission, June 1990.

XI.M19 STEAM GENERATOR TUBE INTEGRITY

Program Description

Steam generator (SG) tubes have experienced tube degradation related to corrosion phenomena, such as primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), pitting, and wastage, along with other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue. Nondestructive examination (NDE) techniques are used to identify tubes that are defective and need to be removed from service or repaired in accordance with the guidelines of the plant technical specifications. In addition, operational leakage limits are included to ensure that, should substantial tube leakage develop, prompt action is taken to avoid rupture of the leaking tubes. These limits are included in plant technical specifications, such as standard technical specifications of NUREG-1430, Rev. 1, for Babcock & Wilcox pressurized water reactors (PWRs); NUREG-1431, Rev. 1, for Westinghouse PWRs; and NUREG-1432, Rev. 1, for Combustion Engineering PWRs.

The technical specifications specify SG inspection scope and frequency, and acceptance criteria for the plugging and repair of flawed tubes. The Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded Steam Generator Tubes," provides guidelines for determining the tube repair criteria and operational leakage limits. Acceptance criteria for the plugging and repair of flawed tubes are incorporated in the plant technical specifications.

However, plants may apply for changes in their technical specifications to provide an alternate regulatory basis for SG degradation management. The NRC has approved changes in the technical specification tube repair criteria at certain plants. Examples include the alternate voltage-based repair criteria of NRC Generic Letter (GL) 95-05 and certain sleeving process. In addition, all PWR licensees have committed voluntarily to a SG degradation management program described in the Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines." This program references a number of industry guidelines and incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. These guidelines are currently under NRC review. The NEI 97-06 document (a) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis, and (b) provides guidance for monitoring and maintaining the tubes to provide assurance that the performance criteria are met at all times between scheduled inspections of the tubes. The NEI 97-06 program includes an assessment of degradation mechanisms that considers operating experience from similar SGs to identify degradation mechanisms and, for each mechanism, defines the inspection techniques, measurement uncertainty, as well as the sampling strategy. The industry guidelines provide criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data, including procedures, probe selection, analysis protocols, and reporting criteria. The performance criteria pertain to structural integrity, accident-induced leakage, and operational leakage. The SG monitoring program includes guidance on assessment of degradation mechanisms, inspection, tube integrity assessment, maintenance, plugging, repair, and leakage monitoring, as well as procedures for monitoring and controlling secondary-side and primary-side water chemistry. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry and secondary water chemistry.

As evaluated below, the plant technical specifications, incorporating NEI 97-06 as approved by the staff and any other alternate regulatory bases for SG degradation management that have been previously approved by the staff for that plant, are adequate to manage the effects of aging on the SG tubes. However, because NEI 97-06 is still under staff review, until the staff has approved NEI 97-06, the applicant's program should be reviewed on a plant-specific basis.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of the program is specific to SG tubes. The program includes preventive measures to mitigate degradation related to corrosion phenomena; assessment of degradation mechanisms; inservice inspection (ISI) of steam generator tubes to detect degradation; evaluation and plugging or repair, as needed; and leakage monitoring to maintain the structural and leakage integrity of the pressure boundary. Tube inspection scope and frequency, plugging or repair, and leakage monitoring are in accordance with the plant technical specifications.

2. ***Preventive Actions:*** The program includes preventive measures to mitigate degradation related to corrosion phenomena. The guidelines in NEI 97-06 include foreign material exclusion as a means to inhibit fretting and wear degradation. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry," of this report.

3. ***Parameters Monitored/Inspected:*** The inspection activities in the program detect flaws in tubing or degradation of secondary side internals needed to maintain tubing integrity. Flaws are removed based on technical specification repair criteria. Degradation of steam generator internals is evaluated for corrective actions.

4. ***Detection of Aging Effects:*** The inspection requirements in the technical specifications are intended to detect tube degradation (i.e., aging effects), if it should occur. The NEI 97-06 document, which is currently under NRC staff review, provides additional guidance on inspection programs to detect degradation. The intent of the inspection and repair criteria is to provide assurance of continued tube integrity between inspections.

5. ***Monitoring and Trending:*** Condition monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied. Operational assessments are performed after inspections to verify that structural and leakage integrity are maintained during the operating interval until the next required inspection, which is selected in accordance with the technical specifications and staff approved NEI 97-06 guidelines. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment.

6. ***Acceptance Criteria:*** Assessment of tube integrity and plugging or repair criteria of flawed tubes is in accordance with the plant technical specifications. The criteria for plugging or repairing SG tubes are based on NRC RG 1.121 or other criteria previously reviewed and approved by the staff and incorporated into the plant technical specifications. Some examples that are applicable under certain circumstances include P*, F*, L*, or NRC GL 95-05.

   For general and pitting corrosion, the acceptance criteria are in accordance with staff approved NEI 97-06 guidelines. Also, loose parts or foreign objects that are found are removed from the SGs unless it can be shown by evaluation that these objects do not cause unacceptable tube damage. The evaluation is to define an acceptable operating interval.

For Westinghouse steam generator tube plugs, limits for the life of the plug and correlations for estimating their life are contained in WCAP-12244 and WCAP-12245.

7. ***Corrective Actions:*** Tubes containing flaws that do not meet the acceptance criteria are plugged or repaired. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Failures to detect some flaws, uncertainties in flaw sizing, inaccuracies in flaw locations, and the inability to detect some cracks at locations with dents have been reviewed in NRC Information Notice (IN) 97-88. Recent experience indicates the importance of performing a complete inspection by using appropriate techniques and equipment for the reliable detection of tube degradation and to provide assurance that new forms of degradation are detected. Implementation of the program provides reasonable assurance that SG tube integrity is maintained consistent with the plant's licensing basis for the period of extended operation. Experience with the condition and operational assessments required for plants that have implemented the alternate repair criteria in NRC GL 95-05 has shown that the predictions of the operational assessments have generally been consistent with the results of the subsequent condition monitoring assessments. In cases where discrepancies have been noted, adjustments have been made in the operational assessment models to improve agreement in subsequent assessments. In addition, NEI has prepared NEI 97-06 to incorporate lessons learned from plant operation experience and SG inspections and is under staff review.

References

EPRI TR-102134, *PWR Secondary Water Chemistry Guidelines: Revision 3,* Electric Power Research Institute, Palo Alto, CA, May 1993.

EPRI TR-105714, *PWR Primary Water Chemistry Guidelines: Revision 3,* Electric Power Research Institute, Palo Alto, CA, November 1995.

EPRI TR-107569, *PWR Steam Generator Examination Guidelines: Revision 5,* Electric Power Research Institute, Palo Alto, CA, September 1997.

NEI 97-06, Rev. 1, *Steam Generator Program Guidelines,* Nuclear Energy Institute, January 2000.

NRC Generic Letter 95-05, *Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking,* U.S. Nuclear Regulatory Commission, August 3, 1995.

NRC Information Notice, 97-88, *Experiences during Recent Steam Generator Inspections*, U.S. Nuclear Regulatory Commission, December 12, 1997.

NRC Regulatory Guide, 1.83, Rev. 1, *Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, July 1975.

NRC Regulatory Guide, 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, August 1976.

NUREG-1430, Rev. 1, *Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

NUREG-1431, Rev. 1, *Standard Technical Specifications for Westinghouse Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

NUREG-1432, Rev. 1, *Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

WCAP-12244 and WCAP-12245, *Steam Generator Tube Plug Integrity Summary Report*, Addendum 2 to Revision 3, Westinghouse Electric Corporation, PA, May 1991.

XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety-related systems, structures, and components (SSC) to the ultimate heat sink (UHS). If an intermediate system is used between the safety-related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of NRC GL 89-13. The guidelines of NRC GL 89-13 include (a) surveillance and control of biofouling; (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walkdown inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.

2. ***Preventive Actions:*** The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of NRC GL 89-13 includes a condition and performance monitoring program; control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists; or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically influenced corrosion (MIC) and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.

3. ***Parameters Monitored/Inspected:*** Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

4. ***Detection of Aging Effects:*** Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing, are effective methods to measure surface condition and the extent of wall

thinning associated with the service water system piping and components, when determined necessary.

5. ***Monitoring and Trending:*** Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

6. ***Acceptance Criteria:*** Biofouling is removed or reduced as part of the surveillance and control process. The program for managing biofouling and aggressive cooling water environments for OCCW systems is preventive. Acceptance criteria are based on effective cleaning of biological fouling organisms and maintenance of protective coatings or linings are emphasized.

7. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Significant microbiologically influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems.

References

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Equipment*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, U.S. Nuclear Regulatory Commission, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, U.S. Nuclear Regulatory Commission, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, U.S. Nuclear Regulatory Commission, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems*, U.S. Nuclear Regulatory Commission, November 20, 1986.

XI.M21 CLOSED-CYCLE COOLING WATER SYSTEM

Program Description

The program includes (a) preventive measures to minimize corrosion and (b) surveillance testing and inspection to monitor the effects of corrosion on the intended function of the component. The program relies on maintenance of system corrosion inhibitor concentrations within specified limits of Electric Power Research Institute [EPRI] TR-107396 to minimize corrosion. Surveillance testing and inspection in accordance with standards in EPRI TR-107396 for closed-cycle cooling water (CCCW) systems is performed to evaluate system and component performance. These measures will ensure that the CCCW system and components serviced by the CCCW system are performing their functions acceptably.

Evaluation and Technical Basis

1. ***Scope of Program:*** A CCCW system is defined as part of the service water system that is not subject to significant sources of contamination, in which water chemistry is controlled and in which heat is not directly rejected to a heat sink. The program described in this section applies only to such a system. If one or more of these conditions are not satisfied, the system is to be considered an open-cycle cooling water system. The staff notes that if the adequacy of cooling water chemistry control can not be confirmed, the system is treated as an open-cycle system as indicated in Action III of Generic Letter (GL) 89-13.

2. ***Preventive Actions:*** The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintenance of system corrosion inhibitor concentrations within specified limits of EPRI TR-107396 to minimize corrosion. The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments and application of corrosion inhibitor in the CCCW system to mitigate general, crevice, and pitting corrosion.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors the effects of corrosion by surveillance testing and inspection in accordance with standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure.

4. ***Detection of Aging Effects:*** Control of water chemistry does not preclude corrosion at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion would result in degradation of system or component performance. The extent and schedule of inspections and testing in accordance with EPRI TR-107396, assure detection of corrosion before the loss of intended function of the component. Performance and functional testing in accordance with EPRI TR-107396, ensures acceptable functioning of the CCCW system or components serviced by the CCCW system. For systems and components in continuous operation, performance adequacy is determined by monitoring data trends for evaluation of heat transfer fouling, pump wear characteristics, and branch flow changes. Components not in operation are periodically tested to ensure operability.

5. ***Monitoring and Trending:*** The frequency of sampling water chemistry varies and can occur on a continuous, daily, weekly, or as needed basis, as indicated by plant operating conditions. Per EPRI TR-107396, performance and functional tests are performed at least every 18 months to demonstrate system operability, and tests to evaluate heat removal

capability of the system and degradation of system components are performed every five years. The testing intervals may be adjusted on the basis of the results of the reliability analysis, type of service, frequency of operation, or age of components and systems.

6. ***Acceptance Criteria:*** Corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. System and component performance test results are evaluated in accordance with the guidelines of EPRI TR-107396. Acceptance criteria and tolerances are also based on system design parameters and functions.

7. ***Corrective Actions:*** Corrosion inhibitor concentrations outside the allowable limits are returned to the acceptable range within the time period specified in the EPRI water chemistry guidelines for CCCW. If the system or component fails to perform adequately, corrective actions are taken in accordance with EPRI TR-107396. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Degradation of closed-cycle cooling water systems due to corrosion product buildup (NRC Licensee Event Report [LER] 93-029-00) or through-wall cracks in supply lines (NRC LER 91-019-00) has been observed in operating plants. Accordingly, operating experience demonstrates the need for this program.

References

EPRI TR-107396, *Closed Cooling Water Chemistry Guidelines*, Electric Power Research Institute, Palo Alto, CA, November 1997.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Equipment*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Licensee Event Report LER #91-019-00, *Loss of Containment Integrity due to Crack in Component Cooling Water Piping*, October 26, 1991.

NRC Licensee Event Report LER #93-029-00, *Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components*, December 13, 1993.

XI.M22 BORAFLEX MONITORING

Program Description

A Boraflex monitoring program for the actual Boraflex panels is implemented in the spent fuel racks to assure that no unexpected degradation of the Boraflex material would compromise the criticality analysis in support of the design of spent fuel storage racks. The applicable aging management program (AMP), based on manufacturer's recommendations, relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained. The frequency of the inspection and testing depends on the condition of the Boraflex, with a maximum of five years. Certain accelerated samples are tested every two years. Results based on test coupons have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded. Therefore, this AMP includes: (1) performing neutron attenuation testing, called blackness testing, to determine gap formation in Boraflex panels; (2) completing sampling and analysis for silica levels in the spent fuel pool water and trending the results by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis (depending on Boraflex panel condition); and (3) measuring boron areal density by techniques such as the BADGER device. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected future Boraflex degradation.

Evaluation and Technical Basis

1. ***Scope of Program:*** The AMP manages the effects of aging on sheets of neutron-absorbing materials affixed to spent fuel racks. For Boraflex panels, gamma irradiation and long-term exposure to the wet pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets.

2. ***Preventive Actions:*** For Boraflex panels, monitoring silica levels in the storage pool water, measuring gap formation by blackness testing, periodically measuring boron areal density, and applying predictive codes, are performed. These actions ensure that degradation of the neutron-absorbing material is identified and corrected so the spent fuel storage racks will be capable of performing their intended functions during the period of extended operation, consistent with current licensing basis (CLB) design conditions.

3. ***Parameters Monitored/Inspected:*** The parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25% silica, 25% polydimethyl siloxane polymer, and 50% boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.

4. ***Detection of Aging Effects:*** The amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present through the use of a predictive code. This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device.

5. ***Monitoring and Trending:*** The periodic inspection measurements and analysis are to be compared to values of previous measurements and analysis to provide a continuing level of data for trend analysis.

6. ***Acceptance Criteria:*** The 5% subcriticality margin of the spent fuel racks is to be maintained for the period of extended operation.

7. ***Corrective Actions:*** Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts, or other options which are available to maintain a subcriticality margin of 5%. As discussed in the appendix of this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, site review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix of this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See item 8, above.

10. ***Operating Experience:*** The NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 in., with the largest 4 in.) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. The NRC IN 93-70 and 95-38 and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. Two spent fuel rack cells with about 12 years of service have only 40% of the Boraflex remaining. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable, therefore, measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water and verified periodically, is performed during the period of extended operation. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

References

BNL-NUREG-25582, *Corrosion Considerations in the Use of Boral in Spent Fuel Storage Pool Racks*, January 1979.

EPRI NP-6159, *An Assessment of Boraflex Performance in Spent Nuclear Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 14, 1988.

EPRI TR-101986, *Boraflex Test Results and Evaluation*, Electric Power Research Institute, Palo Alto, CA, March 1, 1993.

EPRI TR-103300, *Guidelines for Boraflex Use in Spent-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 1, 1993.

NRC Generic Letter 96-04, *Boraflex Degradation in Spent Fuel Pool Storage Racks*, U.S. Nuclear Regulatory Commission, June 26, 1996.

NRC Information Notice 87-43, *Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1987.

NRC Information Notice 93-70, *Degradation of Boraflex Neutron Absorber Coupons*, U.S. Nuclear Regulatory Commission, September 10, 1993.

NRC Information Notice 95-38, *Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1995.

NRC Regulatory Guide 1.26, Rev. 3, *Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment)*, U.S. Nuclear Regulatory Commission, February 1976.

XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

Most commercial nuclear facilities have between 50 and 100 cranes. Many are industrial grade cranes which meet the requirements of 29 CFR Volume XVII, Part 1910, and Section 1910.179. Most are not within the scope of 10 CFR 54.4, and therefore are not required to be part of the integrated plant assessment (IPA).

Normally, fewer than 10 cranes fall within the scope of 10 CFR 54.4. These cranes comply with the Maintenance Rule requirements provided in 10 CFR 50.65. The Nuclear Regulatory Commission Regulatory Guide (RG) 1.160 provides guidance for monitoring the effectiveness of maintenance at nuclear power plants.

The program demonstrates that testing and monitoring programs have been implemented and have ensured that the structures, systems, and components of these cranes are capable of sustaining their rated loads. This is their intended function during the period of extended operation. It is noted that many of the systems and components of these cranes perform an intended function with moving parts or with a change in configuration, or subject to replacement based on qualified life. In these instances, these types of crane systems and components are not within the scope of this aging management program (AMP). This program is primarily concerned with structural components that make up the bridge and trolley. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," provides specific guidance on the control of overhead heavy load cranes.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system.

2. ***Preventive Actions:*** No preventive actions are identified. The crane program is an inspection program.

3. ***Parameters Monitored/Inspected:*** The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The number and magnitude of lifts made by the crane are also reviewed.

4. ***Detection of Aging Effect:*** Crane rails and structural components are visually inspected on a routine basis for degradation. Functional tests are also performed to assure their integrity.

5. ***Monitoring and Trending:*** Monitoring and trending are not required as part of the crane inspection program.

6. ***Acceptance Criteria:*** Any significant visual indication of loss of material due to corrosion or wear are evaluated according to applicable industry standards and good industry practice. The crane may also have been designed to a specific Service Class as defined in the EOCI Specification #61 (or later revisions), or CMAA Specification #70 (or later revisions), or CMAA Specification #74 (or later revisions). The specification that was applicable at the time the crane was manufactured is used.

7. ***Corrective Actions:*** Site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Because of the requirements for monitoring the effectiveness of maintenance at nuclear power plants provided in 10 CFR 50.65, there has been no history of corrosion-related degradation that has impaired cranes. Likewise, because cranes have not been operated beyond their design lifetime, there have been no significant fatigue-related structural failures.

References

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, January 1997.

Crane Manufactures Association of America, Inc., CMAA Specification No. 70, *Specifications for Electric Overhead Traveling Cranes,* 1970 (or later revisions).

Crane Manufactures Association of America, Inc., CMAA Specification No. 74, *Specifications for Top Running and Under Running Single Girder Electric Overhead Traveling Cranes,* 1974 (or later revisions).

Electric Overhead Crane Institute, Inc., EOCI Specification No. 61, *Specifications for Electric Overhead Traveling Cranes,* 1961 (or later revisions).

NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, 1980.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1997.

XI.M24 COMPRESSED AIR MONITORING

Program Description

The program consists of inspection, monitoring, and testing of the entire system, including (a) frequent leak testing of valves, piping, and other system components, especially those made of carbon steel; and (b) preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. The aging management program (AMP) provides for timely corrective actions to ensure that the system is operating within specified limits.

The AMP is based on results of the plant owners response to the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14, augmented by previous NRC Information Notices IN 81-38, IN 87-28, and IN 87-28 S1, and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01. The NRC GL 88-14, issued after several years of study of problems and failures of instrument air systems, recommends each holder of an operating license to perform an extensive design and operations review and verification of its instrument air system. The GL 88-14 also recommends the licensees to describe their program for maintaining proper instrument air quality. The AMP also incorporates provisions conforming to the guidance of the Electric Power Research Institute (EPRI) NP-7079, issued in 1990, to assist utilities in identifying and correcting system problems in the instrument air system and to enable them to maintain required industry safety standards. Subsequent to these initial actions by all plant licensees to implement an improved AMP, some utilities decided to replace their instrument air system with newer models and types of equipment. The EPRI then issued TR-108147, which addresses maintenance of the latest compressors and other instrument air system equipment currently in use at those plants. The American Society of Mechanical Engineers operations and maintenance standards and guides (ASME OM-S/G-1998, Part 17) provides additional guidance to the maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program manages the effects of corrosion and the presence of unacceptable levels of contaminants on the intended function of the compressed air system. The AMP includes frequent leak testing of valves, piping, and other system components, especially those made of carbon steel, and a preventive maintenance program to check air quality at several locations in the system.

2. ***Preventive Actions:*** The system air quality is monitored and maintained in accordance with the plant owner's testing and inspection plans, which are designed to ensure that the system and equipment meet specified operability requirements. These requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME OM-S/G-1998, Part 17; ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147. The preventive maintenance program addresses various aspects of the inoperability of air-operated components due to corrosion and the presence of oil, water, rust, and other contaminants.

3. ***Parameters Monitored/Inspected:*** Inservice inspection (ISI) and testing is performed to verify proper air quality and confirm that maintenance practices, emergency procedures, and training are adequate to ensure that the intended function of the air system is maintained.

4. ***Detection of Aging Effects:*** Guidelines in EPRI NP-7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17, ensure timely detection of degradation of the compressed air system function. Degradation of the piping and any equipment would become evident by observation of excessive corrosion, by the discovery of unacceptable leakage rates, and by failure of the system or any item of equipment to meet specified performance limits.

5. ***Monitoring and Trending:*** Effects of corrosion and the presence of contaminants are monitored by visual inspection and periodic system and component tests, including leak rate tests on the system and on individual items of equipment. These tests verify proper operation by comparing measured values of performance with specified performance limits. Test data are analyzed and compared to data from previous tests to provide for timely detection of aging effects.

6. ***Acceptance Criteria:*** Acceptance criteria is established for the system and for individual equipment that contain specific limits or acceptance ranges based on design basis conditions and/or equipment vendor specifications. The testing results are analyzed to verify that the design and performance of the system is in accordance with its intended function.

7. ***Corrective Actions:*** Corrective actions are taken if any parameters are out of acceptable ranges, such as moisture content in the system air. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38, IN 87-28, IN 87-28 S1 and license event report (LER) 50-237/94-005-3. Some of the systems that have been significantly degraded or have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal system. As a result of NRC GL 88-14 and consideration of INPO SOER 88-01, EPRI NP-7079, and EPRI TR-108147, performance of air systems has improved significantly.

References

ASME OM-S/G-1998, Part 17, *Performance Testing of Instrument Air Systems Information Notice Light-Water Reactor Power Plants*, 1ISA-S7.0.1-1996, "Quality Standard for Instrument Air," American Society of Mechanical Engineers, New York, NY, 1998.

EPRI NP-7079, *Instrument Air System: A Guide for Power Plant Maintenance Personnel*, Electric Power Research Institute, Palo Alto, CA., December 1990.

EPRI/NMAC TR-108147, *Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079*, Electric Power Research Institute, Palo Alto, CA., March 1998.

INPO SOER 88-01, *Instrument Air System Failures*, May 18, 1988.

NRC Generic Letter 88-14, *Instrument Air Supply Problems Affecting Safety-Related Equipment*, U.S. Nuclear Regulatory Commission, August 8, 1988.

NRC Information Notice 81-38, *Potentially Significant Equipment Failures Resulting from Contamination of Air-Operated Systems*, U.S. Nuclear Regulatory Commission, December 17, 1981.

NRC Information Notice 87-28, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, June 22, 1987.

NRC Information Notice 87-28, Supplement 1, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, December 28, 1987.

NRC Licensee Event Report LER 50-237/94-005-3, *Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction*, U.S. Nuclear Regulatory Commission, April 23, 1997.

XI.M25 BWR REACTOR WATER CLEANUP SYSTEM

Program Description

The program includes inservice inspection (ISI) and monitoring and control of reactor coolant water chemistry to manage the effects of stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system. Based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC Generic Letter (GL) 88-01. Coolant water chemistry is monitored and maintained in accordance with the Electric Power Research Institute (EPRI) guidelines in boiling water reactor vessel and internals project (BWRVIP)-29 (TR-103515) to minimize the potential of crack initiation and growth due to SCC or IGSCC.

Evaluation and Technical Basis

1. ***Scope of Program:*** Based on the NRC letter (September 15, 1995) on the screening criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 to monitor SCC or IGSCC and its effects on the intended function of austenitic SS piping. The screening criteria include:

   a. Satisfactory completion of all actions requested in NRC GL 89-10,

   b. No detection of IGSCC in RWCU welds inboard of the second isolation valves (ongoing inspection in accordance with the guidance in NRC GL 88-01), and

   c. No detection of IGSCC in RWCU welds outboard of the second isolation valves after inspecting a minimum of 10% of the susceptible piping.

   No IGSCC inspection is recommended for plants that meet all three criteria or that meet criterion (a) and piping is made of material that is resistant to IGSCC.

2. ***Preventive Actions:*** The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG-0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered to be resistant to SCC; other nickel-alloys, such as Alloy 600, are evaluated on an individual basis. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

   The program delineated in NUREG-0313 and NRC GL 88-01 varies depending on the plant-specific reactor water chemistry to mitigate SCC or IGSCC.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detection and sizing of cracks by implementing the inspection guidelines delineated in the NRC screening criteria for the RWCU piping outboard of isolation valves. The following schedules are followed:

   Schedule A: No inspection is required for plants that meet all three criteria set forth above, or if they meet only criterion (a). Piping is made of material that is resistant to IGSCC, as described above in preventive actions.

   Schedule B: For plants that meet only criterion (a): Inspect at least 2% of the welds or two welds every refueling outage, whichever sample is larger.

   Schedule C: For plants that do not meet criterion (a): Inspect at least 10% of the welds every refueling outage.

4. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, sample expansion, and leak detection guidelines are based on the guidelines of NRC GL 88-01.

   The NRC GL 88-01 recommends that the detailed inspection procedure, equipment, and examination personnel be qualified by a formal program approved by the NRC. Inspection can reveal crack initiation and growth and leakage of coolant. The extent and frequency of inspections recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce the residual stresses, and how the weld was repaired if it had been cracked).

5. ***Monitoring and Trending:*** The extent and schedule for inspection in accordance with the recommendations of NRC GL 88-01 provide timely detection of cracks and leakage of coolant. Based on inspection results, NRC GL 88-01 provides guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.

6. ***Acceptance Criteria:*** The NRC GL 88-01 recommends that any indication detected be evaluated in accordance with the requirements of ASME Section XI, Subsection IWB-3640 (1995 edition through the 1996 addenda).

7. ***Corrective Actions:*** The guidance for weld overlay repair, stress improvement, or replacement is provided in NRC GL 88-01. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The IGSCC has occurred in small- and large-diameter boiling water reactor (BWR) piping made of austenitic SSs or nickel alloys. The comprehensive program outlined in NRC GL 88-01 and NUREG-0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

References

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-29 (EPRI TR-103515), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry,* Electric Power Research Institute, Palo Alto, CA, February 1994.

Letter from Joseph W. Shea, U.S. Nuclear Regulatory Commission, to George A. Hunter, Jr., PECO Energy Company, *Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M92442 and M92443),* September 15, 1995.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,* U.S. Nuclear Regulatory Commission, January 25, 1988.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping,* W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

XI.M26 FIRE PROTECTION

Program Description

For operating plants, the fire protection aging management program (AMP) includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection program requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The AMP also includes periodic inspection and test of halon/carbon dioxide fire suppression system.

Evaluation and Technical Basis

1. ***Scope of Program:*** For operating plants, the AMP manages the aging effects on the intended function of the penetration seals, fire barrier walls, ceilings, and floors, and all fire rated doors (automatic or manual) that perform a fire barrier function. It also manages the aging effects on the intended function of the fuel supply line. The AMP also includes management of the aging effects on the intended function of the halon/carbon dioxide fire suppression system.

2. ***Preventive Actions:*** For operating plants, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing structures, systems, and components important to safety.

3. ***Parameters Monitored/Inspected:*** Visual inspection of 10% of each type of penetration seal is performed during walkdowns carried out at least once every refueling outage. These inspections examine any sign of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals which are directly caused by increased hardness and shrinkage of seal material due to weathering. Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Hollow metal fire doors are visually inspected at least once bi-monthly for holes in the skin of the door. Fire door clearances are also checked at least once bi-monthly as part of an inspection program. Function tests of fire doors are performed daily, weekly, or monthly (which maybe plant specific) to verify the operability of automatic hold-open, release, closing mechanisms, and latches.

   The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detecting any degradation of the fuel supply line.

   Periodic visual inspection and function test at least once every six months examines the signs of degradation of the halon/carbon dioxide fire suppression system. The suppression agent charge pressure is monitored in the test. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damage to dampers, are observed during these tests. Inspections performed at least once every month verify that the extinguishing agent supply valves are open and the system is in automatic mode.

4. ***Detection of Aging Effects:*** Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture of seals. Visual inspection (VT-1 or equivalent) of 10% of each type of seal in walkdowns is performed at least once every refueling outage. If any sign of degradation is detected within that 10%, the scope of the inspection and frequency is expanded to ensure timely detection of increased hardness and shrinkage of the penetration seal before the loss of the component intended function. Visual inspection (VT-1 or equivalent) of the fire barrier walls, ceilings, and floors performed in walkdown at least once every refueling outage ensures timely detection for concrete cracking, spalling, and loss of material. Visual inspection (VT-3 or equivalent) detects any sign of degradation of the fire door such as wear and missing parts. Function tests promptly detect deficiencies in operational conditions. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.

   Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pump ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before the loss of the component intended function.

   In the test of the halon/carbon dioxide fire suppression system, the suppression agent charge pressure is verified to be within in the normal band. Visual inspection detects any sign of degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/carbon dioxide fire suppression system before the loss of the component intended function. The monthly inspection ensures that the extinguishing agent supply valves are open and the system is in automatic mode.

5. ***Monitoring and Trending:*** The aging effects of weathering on fire barrier penetration seals are detectable by visual inspection and, based on operating experience, visual inspections performed at least once every refueling outage to detect any sign of degradation of fire barrier penetration seals prior to loss of the intended function.

   Concrete cracking, spalling, and loss of material are detectable by visual inspection and, based on operating experience, visual inspection performed at least once every refueling outage detects any sign of degradation of the fire barrier walls, ceilings, and floors before there is a loss of the intended function. Wear, missing parts, or holes in the fire door are detectable by visual inspection and, based on operating experience, the visual inspection and function test performed bi-monthly which detects degradation of the fire doors prior to loss of the intended function.

   The performance of the fire pump is monitored during the periodic test to detect any degradation in the fuel supply lines. Periodic testing provides data (e.g., pressure) for trending necessary.

   The performance of the halon/carbon dioxide fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

6. ***Acceptance Criteria:*** Inspection results are acceptable if there are no visual indications of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals, no visual indications of concrete cracking, spalling and loss of material of fire barrier walls, ceilings, and floors, no visual indications of missing parts, holes, and wear and no deficiencies in the functional tests of fire doors. No corrosion

is acceptable in the fuel supply line for the diesel-driven fire pump. Also, any signs of corrosion and mechanical damage of the halon/carbon dioxide fire suppression system are not acceptable.

7. ***Corrective Actions:*** For fire protection structures and components identified within scope that are subject to an aging management review for license renewal, the applicant is to expand the scope of the 10 CFR Part 50, Appendix B, program to include these in-scope structures and components to address corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. This commitment is documented in the final safety analysis report (FSAR) supplement in accordance with 10 CFR 54.21(d). As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes (IN 88-56, IN 94-28, and IN 97-70). Degradation of electrical racing way fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (IN 91-47 and GL 92-08). Fire doors have experienced wear of the hinges and handles. Operating experience with the use of this AMP has shown that no corrosion-related problem has been reported for the fuel supply line, pump casing of the diesel-driven fire pump, and the halon/carbon dioxide suppression system. No significant aging related problems have been reported of fire protection systems, emergency breathing and auxiliary equipment, and communication equipment.

References

NRC Generic Letter 92-08, *Thermo-Lag 330-1 Fire Barrier*, December 17, 1992.

NRC Information Notice 88-56, *Potential Problems with Silicone Foam Fire Barrier Penetration Seals*, August 14, 1988.

NRC Information Notice 91-47, *Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test*, August 6, 1991.

NRC Information Notice 94-28, *Potential problems with Fire-Barrier Penetration Seals*, April 5, 1994.

NRC Information Notice 97-70, *Potential problems with Fire Barrier Penetration Seals*, September 19, 1997.

XI.M27 FIRE WATER SYSTEM

Program Description

This aging management program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated. In addition to NFPA codes and standards, which do not currently contain programs to manage aging, portions of the fire protection sprinkler system, which are not routinely subjected to flow, are to be subjected to full flow tests at the maximum design flow and pressure before the period of extended operation (and at not more than 5-year intervals thereafter). In addition, a sample of sprinkler heads is to be inspected by using the guidance of NFPA 25, Section 2.3.3.1. This NFPA section states that "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing. Finally, portions of fire protection suppression piping located aboveground and exposed to water are disassembled and visually inspected internally once every refueling outage. The purpose of the full flow testing and internal visual inspections is to ensure that corrosion, microbiological influenced corrosion (MIC), or biofouling aging effects are managed such that the system function is maintained.

Evaluation and Technical Basis

1. ***Scope of Program:*** The aging management program focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water. Hose station and standpipe are considered as piping in the AMP.

2. ***Preventive Actions:*** To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted.

3. ***Parameters Monitored/Inspected:*** Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. The NRC GL 89-13 recommends periodic flow testing of infrequently used loops of the fire water system at the maximum design flow to ensure that the system maintains its intended function.

4. ***Detection of Aging Effects:*** Fire protection system testing is performed to assure required pressures. Internal inspections of aboveground fire protection piping and the smaller diameter fire suppression piping are performed on system components (when they are disassembled) to identify evidence of loss of material due to corrosion. Repair and replacement actions are initiated as necessary. Continuous system pressure monitoring, periodic system flow testing performed, and internal inspections of aboveground piping are effective means to ensure that corrosion and biofouling are not occurring and the system's intended function is maintained. In addition, general requirements of existing fire protection programs include testing and maintenance of fire detection and suppression systems and

surveillance procedures to ensure that fire detectors, as well as fire suppression systems and components, are operable.

Visual inspection of yard fire hydrants performed once every six months ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur.

Sprinkler systems are inspected once every refueling outage to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

5. ***Monitoring and Trending:*** System discharge pressure is monitored continuously. Results of system performance testing are monitored and trended as specified by the NFPA codes and standards. Degradation identified by internal inspection is evaluated.

6. ***Acceptance Criteria:*** The acceptance criteria are (a) the ability of a fire protection system to maintain required pressure, (b) no unacceptable signs of degradation observed during visual assessment of internal system conditions, and (c) that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.

7. ***Corrective Actions:*** For fire water systems and components identified within scope that are subject to an aging management review for license renewal, the applicant is to expand the scope of the 10 CFR Part 50, Appendix B, program to include these in-scope systems and components to address corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions, confirmation process, and administrative controls.

8. **Confirmation Process:** See Item 7, above.

9. **Administrative Controls:** See Item 7, above.

10. ***Operating Experience:*** Water-based fire protection systems designed, inspected, tested and maintained in accordance with the NFPA minimum standards have demonstrated reliable performance.

References

NFPA 25: Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, 1998 Edition.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, July 18, 1989.

XI.M28 BURIED PIPING AND TANKS SURVEILLANCE

Program Description

The program includes surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried carbon steel piping and tanks. Surveillance and preventive measures are in accordance with standard industry practice, based on NACE Standards RP-0285-95 and RP-0169-96, and include external coatings, wrappings, and cathodic protection systems.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program relies on preventive measures, such as coating, wrapping, and cathodic protection, and surveillance, based on NACE Standard RP-0285-95 and NACE Standard RP-0169-96, to manage the effects of corrosion on the intended function of buried tanks and piping, respectively.

2. ***Preventive Actions:*** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment. A cathodic protection system is used to mitigate corrosion where pinholes in the coating allow the piping or components to be in contact with the aggressive soil environment. The cathodic protection imposes a current from an anode onto the pipe or tank to stop corrosion from occurring at defects in the coating.

3. ***Parameters Monitored/Inspected:*** The effectiveness of the coatings and cathodic protection system, per standard industry practice, is determined by measuring coating conductance, by surveying pipe-to-soil potential, and by conducting bell hole examinations to visually examine the condition of the coating.

4. ***Detection of Aging Effects:*** Coatings and wrapping can be damaged during installation or while in service and the cathodic protection system is relied upon to avoid any corrosion at the damaged locations. Degradation of the coatings and wrapping during service will result in the requirement for more current from the cathodic protection rectifier in order to maintain the proper cathodic protect potentials. Any increase in current requirements is an indication of coating and wrapping degradation. A close interval pipe-to-soil potential survey can be used to locate the locations where degradation has occurred.

5. ***Monitoring and Trending:*** Monitoring the coating conductance versus time or the current requirement versus time provide an indication of the condition of the coating and cathodic protection system when compared to predetermined values.

6. ***Acceptance Criteria:*** In accordance with accepted industry practice, per NACE Standard RP-0285-95 and NACE Standard RP-0169-96, the assessment of the condition of the coating and cathodic protection system is to be conducted on an annual basis and compared to predetermined values.

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B,

acceptable in addressing the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Corrosion pits from the outside diameter have been discovered in buried piping with far less than 60 years of operation. Buried pipe that is coated and cathodically protected is unaffected after 60 years of service. Accordingly, operating experience from application of the NACE standards on non-nuclear systems demonstrates the effectiveness of this program.

References

NACE Standard RP-0169-96, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 1996.

NACE Standard RP-0285-95, *Corrosion Control of Underground Storage Tank Systems by Cathodic Protection,* Approved March 1985, revised February 1995.

XI.M29 ABOVEGROUND CARBON STEEL TANKS

Program Description

The program includes preventive measures to mitigate corrosion by protecting the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice. The program also relies on periodic system walkdowns to monitor degradation of the protective paint or coating. However, for storage tanks supported on earthen or concrete foundations, corrosion may occur at inaccessible locations, such as the tank bottom. Accordingly, verification of the effectiveness of the program is to be performed to ensure that significant degradation in inaccessible locations is not occurring and the component intended function will be maintained during the extended period of operation. For reasons set forth below, an acceptable verification program consists of thickness measurement of the tank bottom surface.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program consists of (a) preventive measures to mitigate corrosion by protecting the external surfaces of carbon steel tanks protected with paint or coatings and (b) periodic system walkdowns to manage the effects of corrosion on the intended function of these tanks. Plant walkdowns cover the entire outer surface of the tank up to its surface in contact with soil or concrete.

2. ***Preventive Actions:*** In accordance with industry practice, tanks are coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure. Sealant or caulking at the interface edge between the tank and concrete or earthen foundation mitigates corrosion of the bottom surface of the tank by preventing water and moisture from penetrating the interface, which would lead to corrosion of the bottom surface.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) utilizes periodic plant system walkdowns to monitor degradation of coatings, sealants, and caulking because it is a condition directly related to the potential loss of materials.

4. ***Detection of Aging Effects:*** Degradation of exterior carbon steel surfaces cannot occur without degradation of paint or coatings on the outer surface and of sealant and caulking at the interface between the component and concrete. Periodic system walkdowns to confirm that the paint, coating, sealant, and caulking are intact is an effective method to manage the effects of corrosion on the external surface of the component. However, corrosion may occur at inaccessible locations, such as the tank bottom surface, and thickness measurement of the tank bottom is to be taken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

5. ***Monitoring and Trending:*** The effects of corrosion of the aboveground external surface are detectable by visual techniques. Based on operating experience, plant system walkdowns during each outage provide for timely detection of aging effects. The effects of corrosion of the underground external surface are detectable by thickness measurement of the tank bottom and are monitored and trended if significant material loss is detected.

6. ***Acceptance Criteria:*** Any degradation of paint, coating, sealant, and caulking is reported and will require further evaluation. Degradation consists of cracking, flaking, or peeling of

paint or coatings, and drying, cracking or missing sealant and caulking. Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Coating degradation, such as flaking and peeling, has occurred in safety-related systems and structures (Nuclear Regulatory Commission [NRC] Generic Letter [GL] 98-04). Corrosion damage near the concrete-metal interface and sand-metal interface has been reported in metal containments (NRC Information Notice [IN] 89-79, Supplement 1, and NRC IN 86-99, Supplement 1).

References

NRC Generic Letter 98-04, *Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,* U.S. Nuclear Regulatory Commission, July 14, 1998.

NRC Information Notice 86-99, *Degradation of Steel Containments,* U.S. Nuclear Regulatory Commission, December 8, 1986.

NRC Information Notice 86-99, Supplement 1, *Degradation of Steel Containments,* U.S. Nuclear Regulatory Commission, February 14, 1991.

NRC Information Notice 89-79, *Degraded Coatings and Corrosion of Steel Containment Vessel,* U.S. Nuclear Regulatory Commission, December 1, 1989.

NRC Information Notice 89-79, Supplement 1, *Degraded Coatings and Corrosion of Steel Containment Vessel,* U.S. Nuclear Regulatory Commission, June 29, 1990.

XI.M30 FUEL OIL CHEMISTRY

Program Description

The program includes (a) surveillance and maintenance procedures to mitigate corrosion and (b) measures to verify the effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the guidelines of the American Society for Testing Materials (ASTM) Standards D 1796, D 2276, D 2709, and D 4057. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the effectiveness of the program is verified to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. Thickness measurement of tank bottom surfaces is an acceptable verification program.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

2. ***Preventive Actions:*** The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

3. ***Parameters Monitored/Inspected:*** The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, *modified* ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 μm, instead of 0.8 μm. These are the principal parameters relevant to tank structural integrity.

4. ***Detection of Aging Effects:*** Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below acceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

5. ***Monitoring and Trending:*** Water and biological activity or particulate contamination concentrations are monitored and trended at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provide for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

6. ***Acceptance Criteria:*** The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamiination in diesel fuel. Modified ASTM D 2276, Method A is used for determination of particulates. The modification consists of using a filter with a pore size of 3.0 μm, instead of 0.8 μm.

7. ***Corrective Actions:*** Specific corrective actions are implemented in accordance with the plant quality assurance (QA) program. For example, corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. Also, when the presence of biological activity is confirmed, a biocide is added to fuel oil. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The operating experience at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. However, no instances of fuel oil system component failures attributed to contamination have been identified.

References

ASTM D 1796-97, *Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method,* American Society for Testing Materials, West Conshohocken, PA.

ASTM D 2276-00, *Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling,* American Society for Testing Materials, West Conshohocken, PA.

ASTM D 2709-96, *Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge,* American Society for Testing Materials, West Conshohocken, PA.

ASTM D 4057-95(2000), *Standard Practice for Manual Sampling of Petroleum and Petroleum Products,* American Society for Testing Materials, West Conshohocken, PA.

XI.M31 REACTOR VESSEL SURVEILLANCE

Program Description

The Code of Federal Regulations, 10 CFR Part 50, Appendix H, requires that peak neutron fluence at the end of the design life of the vessel will not exceed 10^{17} n/cm^2 (E >1MeV), or that reactor vessel beltline materials be monitored by a surveillance program to meet the American Society for Testing and Materials (ASTM) E 185 Standard. However, the surveillance program in ASTM E 185 is based on plant operation during the current license term, and additional surveillance capsules may be needed for the period of extended operation. Alternatively, an integrated surveillance program for the period of extended operation may be considered for a set of reactors that have similar design and operating features in accordance with 10 CFR Part 50, Appendix H, Paragraph II.C. Additional surveillance capsules may also be needed for the period of extended operation for this alternative.

The existing reactor vessel material surveillance program provides sufficient material data and dosimetry to monitor irradiation embrittlement at the end of the period of extended operation, and to determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux. If surveillance capsules are not withdrawn during the period of extended operation, operating restrictions are to be established to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed.

An acceptable reactor vessel surveillance program consists of the following:

1. The extent of reactor vessel embrittlement for upper-shelf energy and pressure-temperature limits for 60 years is projected in accordance with the Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials." When using NRC RG 1.99, Rev. 2, an applicant has a choice of the following:

   a. Neutron Embrittlement Using Chemistry Tables

   An applicant may use the tables in NRC RG 1.99, Rev. 2, to project the extent of reactor vessel neutron embrittlement for the period of extended operation based on material chemistry and neutron fluence. This is described as Regulatory Position 1 in the RG.

   b. Neutron Embrittlement Using Surveillance Data

   When credible surveillance data are available, the extent of reactor vessel neutron embrittlement for the period of extended operation may be projected according to Regulatory Position 2 in NRC RG 1.99, Rev. 2, based on best fit of the surveillance data. The credible data could be collected during the current operating term. The applicant may have a plant-specific program or an integrated surveillance program during the period of extended operation to collect additional data.

2. An applicant that determines embrittlement by using the NRC RG 1.99, Rev. 2, tables (see item 1[a], above) uses the applicable limitations in Regulatory Position 1.3 of the RG. The limits are based on material properties, temperature, material chemistry, and fluence.

3. An applicant that determines embrittlement by using surveillance data (see item 1[b], above) defines the applicable bounds of the data, such as cold leg operating temperature and neutron fluence. These bounds are specific for the referenced surveillance data. For

example, the plant-specific data could be collected within a smaller temperature range than that in the RG.

4. All pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage. (Note: These specimens are saved for future reconstitution use, in case the surveillance program is reestablished.)

5. If an applicant has a surveillance program that consists of capsules with a projected fluence of less than the 60-year fluence at the end of 40 years, at least one capsule is to remain in the reactor vessel and is tested during the period of extended operation. The applicant may either delay withdrawal of the last capsule or withdraw a standby capsule during the period of extended operation to monitor the effects of long-term exposure to neutron irradiation.

6. If an applicant has a surveillance program that consists of capsules with a projected fluence exceeding the 60-year fluence at the end of 40 years, the applicant withdraws one capsule at an outage in which the capsule receives a neutron fluence equivalent to the 60-year fluence and tests the capsule in accordance with the requirements of ASTM E 185. Any capsules that are left in the reactor vessel provide meaningful metallurgical data (i.e., the capsule fluence does not significantly exceed the vessel fluence at an equivalent of 60 years). For example, in a reactor with a lead factor of three, after 20 years the capsule test specimens would have received a neutron exposure equivalent to what the reactor vessel would see in 60 years; thus, the capsule is to be removed since further exposure would not provide meaningful metallurgical data. Other standby capsules are removed and placed in storage. These standby capsules (and archived test specimens available for reconstitution) would be available for reinsertion into the reactor if additional license renewals are sought (e.g., 80 years of operation). If all surveillance capsules have been removed, operating restrictions are to be established to ensure that the plant is operated under conditions to which the surveillance capsules were exposed and 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 license. 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, an active surveillance program is re-instituted. Any changes to the reactor vessel exposure conditions and the potential need to re-institute a vessel surveillance program is discussed with the NRC staff prior to changing the plant's licensing basis.

7. Applicants without in-vessel capsules use alternative dosimetry to monitor neutron fluence during the period of extended operation, as part of the aging management program (AMP) for reactor vessel neutron embrittlement.

8. The applicant may choose to demonstrate that the materials in the inlet, outlet, and safety injection nozzles are not controlling, so that such materials need not be added to the material surveillance program for the license renewal term.

The reactor vessel monitoring program provides that, if future plant operations exceed the limitations or bounds specified in item 2 or 3, above (as applicable), such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. An applicant without capsules in its reactor vessel is to propose reestablishing the reactor vessel surveillance program to assess the extent of embrittlement. This program will consist of (1) capsules from item 6, above; (2) reconstitution of specimens from item 4, above; and/or (3) capsules made from any available archival materials; or (4) some combination of the three previous options. This program could be a plant-specific program or an integrated surveillance program.

Evaluation and Technical Basis

Reactor vessel surveillance programs are plant specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR Part 50, Appendix H, an applicant submits its proposed withdrawal schedule for approval prior to implementation. Thus, further staff evaluation is required for license renewal.

References

10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements*, Office of the Federal Register, National Archives and Records Administration, 2000.

ASTM E-185, *Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels*, American Society for Testing Materials, Philadelphia, PA.

NRC Regulatory Guide 1.99, Rev. 2, *Radiation Embrittlement of Reactor Vessel Materials,* U.S. Nuclear Regulatory Commission.

XI.M32 ONE-TIME INSPECTION

Program Description

The program includes measures to verify the effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. For example, for structures and components that rely on an AMP, such as water chemistry control, this program verifies the effectiveness of the AMP by confirming that unacceptable degradation is not occurring and the intended function of a component will be maintained during the extended period of operation. One-time inspection is needed to address concerns for the potential long incubation period for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is an acceptable option for this verification. One-time inspection is to provide additional assurance that either aging is not occurring or the evidence of aging is so insignificant that an aging management program is not warranted. For example, for structures and components, such as Class 1 piping with a diameter less than nominal pipe size (NPS) 4 inch that do not receive volumetric examination during inservice inspection, the program confirms that crack initiation and growth due to stress corrosion cracking (SCC) or cyclic loading is not occurring and, therefore, there is no need to manage an aging related degradation for the period of extended operation.

The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

When evidence of an aging effect is revealed by a one-time inspection, the routine evaluation of the inspection results would identify appropriate corrective actions.

As set forth below, an acceptable verification program may consist of a one-time inspection of selected components and susceptible locations in the system. An alternative acceptable program may include routine maintenance or a review of repair records to confirm that these components have been inspected for aging degradation and significant aging degradation has not occurred and thereby verify the effectiveness of existing AMPs. One-time inspection, or any other action or program, is to be reviewed by the staff on a plant-specific basis.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the Generic Aging Lessons Learned (GALL) report. Examples include small bore piping in the reactor coolant system or the feedwater system components in boiling water reactors (BWRs) and pressurized water reactors (PWRs).

2. ***Preventive Actions:*** One-time inspection is an inspection activity independent of methods to mitigate or prevent degradation.

3. ***Parameters Monitored/Inspected:*** The program monitors parameters directly related to the degradation of a component. Inspection is performed in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Code and 10 CFR 50, Appendix B, by using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

4. ***Detection of Aging Effects:*** The inspection includes a representative sample of the system population, and, where practical, focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small-bore piping, actual inspection locations are based on physical accessibility, exposure levels, NDE techniques, and locations identified in Nuclear Regulatory Commission (NRC) Information Notice (IN) 97-46.

   Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. For small-bore piping less than NPS 4 in., including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred. Follow-up of unacceptable inspection findings includes expansion of the inspection sample size and locations.

   The inspection and test techniques prescribed by the program verify any aging effects because these techniques, used by qualified personnel, have been proven effective and consistent with staff expectations. With respect to inspection timing, the one-time inspection is to be completed before the end of the current operating license. The applicant may schedule the inspection in such a way as to minimize the impact on plant operations. However, the inspection is not to be scheduled too early in the current operating term, which could raise questions regarding continued absence of aging effects prior to and near the extended period of operation.

5. ***Monitoring and Trending:*** One-time inspection does not provide specific guidance on monitoring and trending. However, evaluation of the appropriateness of the techniques and timing of the one-time inspection improve with the accumulation of plant-specific and industry-wide experience.

6. ***Acceptance Criteria*:** Any indication or relevant conditions of degradation detected are evaluated. The ultrasonic thickness measurements are to be compared to predetermined limits, such as design minimum wall thickness.

7. ***Corrective Actions:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** One-time inspection is a new program to be applied by the applicant. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with years of industry practice and staff expectations.

References

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* ASME Boiler and Pressure Vessel Code, 1995 edition through the 1996 addenda, American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 97-46, *Unisolable Crack in High-Pressure Injection Piping,* U.S. Nuclear Regulatory Commission, July 9, 1997.

XI.M33 SELECTIVE LEACHING OF MATERIALS

Program Description

The program for selective leaching of materials ensures the integrity of the components made of cast iron, bronze, brass, and other alloys exposed to a raw water, brackish water, treated water, or groundwater environment that may lead to selective leaching of one of the metal components. The aging management program (AMP) includes a one-time visual inspection and hardness measurement of selected components that may be susceptible to selective leaching to determine whether loss of materials due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function for the period of extended operation.

Evaluation and Technical Basis

1. ***Scope of Program:*** This AMP determines the acceptability of the components that may be susceptible to selective leaching and assess their ability to perform the intended function during the period of extended operation. These components include piping, valve bodies and bonnets, pump casings, and heat exchanger components. The materials of construction for these components may include cast iron, brass, bronze, or aluminum-bronze. These components may be exposed to a raw water, treated water, or groundwater environment. The AMP includes a one-time hardness measurement of a selected set of components to determine whether loss of material due to selective leaching is not occurring for the period of extended operation.

   The selective leaching process involves the preferential removal of one of the alloying elements from the material, which leads to the enrichment of the remaining alloying elements. Dezincification (loss of zinc from brass) and graphitization (removal of iron from cast iron) are examples of such a process. Susceptible materials, high temperatures, stagnant-flow conditions, and corrosive environment such as acidic solutions, for example, for brasses with high zinc content, and dissolved oxygen, are conducive to selective leaching.

2. ***Preventive Actions:*** The one-time visual inspection and hardness measurement is an inspection/verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and concentration of corrosive contaminants, and treatment with hydrazine to minimize dissolved oxygen in water are effective in reducing selective leaching.

3. ***Parameters Monitored/Inspected:*** The visual inspection and hardness measurement is to be a one-time inspection. Because selective leaching is a slow acting corrosion process, this measurement is performed just before the beginning of the license renewal period. Follow-up of unacceptable inspection findings includes expansion of the inspection sample size and location.

4. ***Detection of Aging Effects:*** The one-time visual inspection and hardness measurement includes close examination of a select set of components to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation. Selective leaching generally does not cause changes in dimensions and is difficult to detect. However, in certain brasses it causes plug-type dezincification, which can be detected by visual inspection. One acceptable procedure is to visually inspect the susceptible

components closely and conduct Brinell Hardness testing on the inside surfaces of the selected set of components to determine if selective leaching has occurred. If it is occurring, an engineering evaluation is initiated to determine acceptability of the affected components for further service.

5. ***Monitoring and Trending:*** There is no monitoring and trending for the one-time visual inspection and hardness measurement.

6. ***Acceptance Criteria:*** Identification of selective leaching will define the need for further engineering evaluation before the affected components can be qualified for further service. If necessary, the evaluation will include a root cause analysis.

7. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria. The corrective actions program ensures that conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** One-time inspection is a new program to be applied by the applicant. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with years of industry practice and staff expectations.

References

NRC Safety Evaluation Report Related to the License Renewal of Calvert Cliffs Nuclear Power Plant, Units 1 and 2, NUREG-1705, December 1999.

NRC Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3, NUREG-1723, March 2000.

XI.M34 BURIED PIPING AND TANKS INSPECTION

Program Description

The program includes (a) preventive measures to mitigate corrosion, and (b) periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried carbon steel piping and tanks. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried piping and tanks are inspected when they are excavated during maintenance and when a pipe is dug up and inspected for any reason.

As evaluated below, this is an acceptable option to manage buried components, except for the program element/attributes of detection of aging effects (regarding inspection frequency) and operating experience. Thus, the staff further evaluates an applicant's inspection frequency and operating experience with buried components.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program relies on preventive measures such as coating and wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried carbon steel piping and tanks. Loss of material in these components, which may be exposed to aggressive soil environment, is caused by general, pitting, and crevice corrosion, and microbiologically influenced corrosion (MIC). Periodic inspections are performed when the components are excavated for maintenance or for any other reason. The scope of the program covers buried components that are within the scope of license renewal for the plant.

2. ***Preventive Actions:*** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.

3. ***Parameters Monitored/Inspected:*** The program monitors parameters such as coating and wrapping integrity that are directly related to corrosion damage of the external surface of buried carbon steel piping and tanks. Coatings and wrappings are inspected by visual techniques. Any evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage, is an indicator of possible corrosion damage to the external surface of piping and tanks.

4. ***Detection of Aging Effects:*** Periodic inspection of susceptible locations to confirm that coating and wrapping are intact, is an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Buried piping and tanks are inspected when they are excavated during maintenance. The inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. However, because the inspection frequency is plant specific and also depends on the plant operating experience, the applicant's proposed inspection frequency is to be further evaluated for the extended period of operation.

5. ***Monitoring and Trending:*** Results of previous inspections are used to identify susceptible locations.

6. ***Acceptance Criteria:*** Any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures.

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Operating experience shows that the program described here is effective in managing corrosion of external surfaces of buried carbon steel components. However, because the inspection frequency is plant specific and also depends on the plant operating experience, the applicant's plant-specific operating experience is further evaluated for the extended period of operation.

References

None.

XI.S1 ASME SECTION XI, SUBSECTION IWE

Program Description

10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE for steel containments (Class MC) and steel liners for concrete containments (Class CC). The full scope of IWE includes steel containment shells and their integral attachments; steel liners for concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure-retaining bolting. This evaluation covers both the 1992 Edition with the 1992 Addenda and the 1995 Edition with the 1996 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWE and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of steel containments, steel liners of concrete containments, and other containment components for license renewal.

The primary ISI method specified in IWE is visual examination (general visual, VT-3, VT-1). Limited volumetric examination (ultrasonic thickness measurement) and surface examination (e.g., liquid penetrant) may also be necessary in some instances. Bolt preload is checked by either a torque or tension test. IWE specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWE as an aging management program (AMP) for license renewal is provided below.

Evaluation and Technical Basis

1. ***Scope of Program:*** Subsection IWE-1000 specifies the components of steel containments and steel liners of concrete containments within its scope. The components within the scope of Subsection IWE are Class MC pressure-retaining components (steel containments) and their integral attachments; metallic shell and penetration liners of Class CC containments and their integral attachments; containment seals and gaskets; containment pressure-retaining bolting; and metal containment surface areas, including welds and base metal. The concrete portions of containments are inspected in accordance with Subsection IWL.

   Subsection IWE exempts the following from examination:

   (1) Components that are outside the boundaries of the containment as defined in the plant-specific design specification;
   (2) Embedded or inaccessible portions of containment components that met the requirements of the original construction code of record;
   (3) Components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and
   (4) Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (governed by IWB or IWC).

   10 CFR 50.55a(b)(2)(ix) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Examination requirements for containment supports are not within the scope of Subsection IWE.

2. ***Preventive Action:*** No preventive actions are specified; Subsection IWE is a monitoring program.

3. ***Parameters Monitored or Inspected:*** Table IWE-2500-1 specifies seven categories for examination. The categories, parts examined, and examination methods are presented in the following table. The first six examination categories (E-A through E-G) constitute the ISI requirements of IWE. Examination category E-P references 10 CFR Part 50, Appendix J leak rate testing. Appendix J leak rate testing is evaluated as a separate AMP for license renewal in XI.S4.

CATEGORY	PARTS EXAMINED	EXAMINATION METHOD[a]
E-A	Containment surfaces	General visual, visual VT-3
E-B[b]	Pressure retaining welds	Visual VT-1
E-C	Containment surfaces requiring augmented examination	Visual VT-1, volumetric
E-D	Seals, gaskets, and moisture barriers	Visual VT-3
E-F[b]	Pressure retaining dissimilar metal welds	Surface
E-G	Pressure retaining bolting	Visual VT-1, bolt torque or tension test
E-P	All pressure-retaining components (pressure retaining boundary, penetration bellows, airlocks, seals, and gaskets)	10 CFR Part 50, Appendix J (containment leak rate testing)

[a] The applicable examination method (where multiple methods are listed) depends on the particular subcategory within each category.

[b] These two categories are optional, in accordance with 10 CFR 50.55a(b)(2)(ix)(C).

Table IWE-2500-1 references the applicable section in IWE-3500 that identifies the aging effects that are evaluated. The parameters monitored or inspected depend on the particular examination category. For Examination Category E-A, as an example, metallic surfaces (without coatings) are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. For Examination Category E-D, seals, gaskets, and moisture barriers are examined for wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity.

4. ***Detection of Aging Effects:*** The frequency and scope of examination specified in 10 CFR 50.55a and Subsection IWE ensure that aging effects would be detected before they would compromise the design-basis requirements. As indicated in IWE-2400, inservice examinations and pressure tests are performed in accordance with one of two inspection programs, A or B, on a specified schedule. Under Inspection Program A, there are four inspection intervals (at 3, 10, 23, and 40 years) for which 100% of the required examinations

must be completed. Within each interval, there are various inspection periods for which a certain percentage of the examinations are to be performed to reach 100% at the end of that interval. In addition, a general visual examination is performed once each inspection period. After 40 years of operation, any future examinations will be performed in accordance with Inspection Program B. Under Inspection Program B, starting with the time the plant is placed into service, there is an initial inspection interval of 10 years and successive inspection intervals of 10 years each, during which 100% of the required examinations are to be completed. An expedited examination of containment is required by 10 CFR 50.55a in which an inservice (baseline) examination specified for the first period of the first inspection interval for containment is to be performed by September 9, 2001. Thereafter, subsequent examinations are performed every 10 years from the baseline examination. Regarding the extent of examination, all accessible surfaces receive a visual examination such as General Visual, VT-1, or VT-3 (see table in item 3 above). IWE-1240 requires augmented examinations (Examination Category E-C) of containment surface areas subject to degradation. A VT-1 visual examination is performed for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination is performed for areas accessible from only one side.

5. ***Monitoring and Trending:*** With the exception of inaccessible areas, all surfaces are monitored by virtue of the examination requirements on a scheduled basis. When component examination results require evaluation of flaws, evaluation of areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

   IWE-2430 specifies that (a) examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards are to be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations, and (b) when additional flaws or areas of degradation that exceed the acceptance standards are revealed, all of the remaining examinations within the same category are to be performed to the extent specified in Table IWE-2500-1 for the inspection interval. Alternatives to these examinations are provided in 10 CFR 50.55a(b)(2)(ix)(D).

6. ***Acceptance Criteria:*** IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments. Table IWE-3410-1 presents criteria to evaluate the acceptability of the containment components for service following the preservice examination and each inservice examination. This table specifies the acceptance standard for each examination category. Most of the acceptance standards rely on visual examinations. Areas that are suspect require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss exceeding 10% of the nominal containment wall thickness, or material loss that is projected to exceed 10% of the nominal containment wall thickness before the next examination, are documented. Such areas are to be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

7. ***Corrective Actions:*** Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in Table-3410-1 are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000. For repair of components within the scope of Subsection IWE, IWE-3124 states that repairs and reexaminations are to comply with IWA-4000. IWA-4000 provides repair specifications for pressure retaining components including metal containments and metallic liners of concrete containments. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective. Subsection IWE states that repairs and reexaminations are to comply with the requirements of IWA-4000. Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** ASME Section XI, Subsection IWE was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. NRC Generic Letter (GL) 87-05 addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region." More recently, NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. The program is to consider the liner plate and containment shell corrosion concerns described in these generic communications. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, is a necessary element of aging management for steel components of steel and concrete containments through the period of extended operation.

References

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2000.

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWA, *General Requirements,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWB, *Requirements for Class 1 Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWC, *Requirements for Class 2 Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Generic Letter 87-05, *Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells,* U.S. Nuclear Regulatory Commission, March 12, 1987.

NRC Information Notice 86-99, *Degradation of Steel Containments,* U.S. Nuclear Regulatory Commission, December 8, 1986 and Supplement 1, February 14, 1991.

NRC Information Notice 88-82, *Torus Shells with Corrosion and Degraded Coatings in BWR Containments,* U.S. Nuclear Regulatory Commission, October 14,1988 and Supplement 1, May 2, 1989.

NRC Information Notice 89-79, *Degraded Coatings and Corrosion of Steel Containment Vessels,* U.S. Nuclear Regulatory Commission, December 1, 1989 and Supplement 1, June 29, 1989.

NRC Information Notice 97-10, *Liner Plate Corrosion in Concrete Containment,* U.S. Nuclear Regulatory Commission, March 13, 1997.

XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. This evaluation covers both the 1992 Edition with the 1992 Addenda and the 1995 Edition with the 1996 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of containment reinforced concrete and unbonded post-tensioning systems for license renewal.

The primary inspection method specified in IWL is visual examination (VT-3C, VT-1, VT-1C). For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWL as an aging management program (AMP) for license renewal is provided below.

Evaluation and Technical Basis

1. ***Scope of Program:*** Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or other components). 10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL, but are included within the scope of Subsection IWE.

2. ***Preventive Action:*** No preventive actions are specified; Subsection IWL is a monitoring program. If a coating program is currently credited for managing the effects of aging of concrete surfaces, then the program is to be continued during the period of extended operation.

3. ***Parameters Monitored or Inspected:*** Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all concrete surfaces and Category L-B for concrete surfaces surrounding tendon anchorages. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R-77. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for

unbonded post tensioning systems. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations.

4. ***Detection of Aging Effects:*** The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five-year intervals. For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Table IWL-2521-1 specifies the number of tendons to be selected for each type (e.g., hoop, vertical, dome, helical, and inverted U) for each inspection period. The minimum number of each tendon type selected for inspection varies from 2 to 4%. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments.

5. ***Monitoring and Trending:*** Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.

6. ***Acceptance Criteria:*** IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R-77 for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and

elongation, tendon wire or strand samples, and corrosion protection medium. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are to be calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation.

7. ***Corrective Actions:*** Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300 "Evaluation" and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. As part of this evaluation, IWL-3300 specifies that the engineering evaluation report include the extent, nature, and frequency of additional examinations. IWL-4000 specifies the requirements for examination of areas that are repaired. Pressure tests following repair or modifications are in accordance with IWL-5000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). Recently, NRC Information Notice (IN) 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in this generic communication. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation.

References

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2000.

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2000.

ACI Standard 201.1R-77, *Guide for Making a Condition Survey of Concrete in Service,* American Concrete Institute.

ACI Standard 349.3R-96, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWA, *General Requirements,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants,* 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 99-10, Revision 1, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment,* U.S. Nuclear Regulatory Commission, October 7, 1999.

XI.S3 ASME SECTION XI, SUBSECTION IWF

Program Description

10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, for Class 1, 2, 3, and MC piping and components and their associated supports. Inservice inspection of supports for ASME piping and components is addressed in Section XI, Subsection IWF. This evaluation covers the 1989 Edition through the 1995 Edition and addenda through the 1996 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWF constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC supports for license renewal.

The IWF scope of inspection for supports is 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). 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.

The evaluation of Subsection IWF as an aging management program (AMP) for license renewal is provided below.

Evaluation and Technical Basis

1. ***Scope of Program:*** For Class 1 piping and component supports, Subsection IWF (1989 edition) refers to Subsection IWB for the inspection scope and schedule. According to Table IWB-2500-1, only 25% of nonexempt supports are subject to examination. Supports exempt from examination are the supports for piping systems that are exempt from examination, according to pipe diameter or service. The same supports are inspected in each 10-year inspection interval. For Class 2, 3, and MC piping and component supports, Subsection IWF (1989 edition) refers to Subsections IWC, IWD, and IWE for the inspection scope and schedule. According to Table IWC-2500-1, 7.5% of nonexempt supports are subject to examination for Class 2 systems. The same supports are inspected in each 10-year inspection interval. No specific numerical percentages are identified in Subsections IWD and IWE for Class 3 and Class MC, respectively.

   Starting with the 1990 addenda to the 1989 edition, the scope of Subsection IWF was revised. The required percentages of each type of nonexempt support subject to examination were incorporated into Table IWF-2500-1. The revised percentages are 25% of Class 1 nonexempt piping supports, 15% of Class 2 nonexempt piping supports, 10% of Class 3 nonexempt piping supports, and 100% of supports other than piping supports (Class 1, 2, 3, and MC). For pipe supports, the total sample consists of supports from each system (such as main steam, feedwater, residual heat removal), where the individual sample sizes are proportional to the total number of nonexempt supports of each type and function within each system. For multiple components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components are required to be examined. To the extent practical, the same supports selected for examination during the first inspection interval are examined during each successive inspection interval.

2. ***Preventive Action:*** No preventive actions are specified; Subsection IWF is an inspection program.

3. ***Parameters Monitored or Inspected:*** IWF specifies visual examination (VT-3) of supports. The parameters monitored or inspected include corrosion; deformation; misalignment; improper clearances; improper spring settings; damage to close tolerance machined or sliding surfaces; and missing, detached, or loosened support items. The visual inspection would be expected to identify relatively large cracks.

   Table IWF-2500-1 (1989 edition) specifies examination of the following:

   (F1.10) Mechanical connections to pressure-retaining components and building structure;
   (F1.20) Weld connections to building structure;
   (F1.30) Weld and mechanical connections at intermediate joints in multi-connected integral and nonintegral supports;
   (F1.40) Clearances of guides and stops, alignment of supports, and assembly of support items;
   (F1.50) Spring supports and constant load supports;
   (F1.60) Sliding surfaces;
   (F1.70) Hot or cold position of spring supports and constant load supports.

   (Starting with the 1990 addenda, these items are listed in paragraph IWF-2500.)

4. ***Detection of Aging Effects:*** VT-3 visual examination is specified in Table IWF-2500-1. The complete inspection scope is repeated every 10-year inspection interval. The qualified VT-3 inspector uses judgment in assessing general corrosion; observed degradation is documented if loss of structural capacity is suspected.

5. ***Monitoring and Trending:*** There is no requirement to monitor or report progressive, time-dependent degradation. Unacceptable conditions, according to IWF-3400, are noted for correction or further evaluation.

6. ***Acceptance Criteria:*** The acceptance standards for visual examination are specified in IWF-3400. In IWF-3410(b)(5), "roughness or general corrosion which does not reduce the load bearing capacity of the support" is given as an example of a "non-relevant condition," which requires no further action. IWF-3410(a) identifies the following conditions as unacceptable:

   (i) deformations or structural degradations of fasteners, springs, clamps, or other support items;
   (ii) missing, detached, or loosened support items;
   (iii) arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;
   (iv) improper hot or cold positions of spring supports and constant load supports;
   (v) misalignment of supports;
   (vi) improper clearances of guides and stops.

Identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b).

7. ***Corrective Actions:*** In accordance with IWF-3122, supports containing unacceptable conditions are evaluated or tested, or corrected before returning to service. Corrective actions are delineated in IWF-3122.2. IWF-3122.3 provides an alternative for evaluation or testing, to substantiate structural integrity and/or functionality. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** To date, IWF sampling inspections have been effective in managing aging effects for ASME Class 1, 2, 3, and MC supports. There is reasonable assurance that the Subsection IWF inspection program will be effective through the period of extended operation.

References

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, January 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWB, *Requirements for Class 1 Components of Light-Water Cooled Power Plants,* 1989 Edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWC, *Requirements for Class 2 Components of Light-Water Cooled Power Plants,* 1989 Edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWD, *Requirements for Class 3 Components of Light-Water Cooled Power Plants,* 1989 Edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 1989 Edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWF, *Requirements for Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants,* 1989 Edition through the 1995 Edition with 1996 Addenda. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

XI.S4 10 CFR PART 50, APPENDIX J

Program Description

As described in 10 CFR Part 50, Appendix J, containment leak rate tests are required "to assure that (a) leakage through the primary reactor containment and systems and components penetrating primary containment shall not exceed allowable leakage rate values as specified in the technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment, and systems and components penetrating primary containment."

Appendix J provides two options, A and B, either of which can be chosen to meet the requirements of a containment LRT program. Under Option A, all of the testing must be performed on a periodic interval. Option B is a performance-based approach. Some of the differences between these options are discussed below, and more detailed information for Option B is provided in the Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.163 and NEI 94-01, Rev. 0.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of the containment LRT program includes all pressure-retaining components. Two types of tests are implemented. Type A tests are performed to measure the overall primary containment integrated leakage rate, which is obtained by summing leakage through all potential leakage paths, including containment welds, valves, fittings, and components that penetrate containment. Type B tests are performed to measure local leakage rates across each pressure-containing or leakage-limiting boundary for containment penetrations. Type A and B tests described in 10 CFR Part 50, Appendix J, are acceptable methods for performing these LRTs. Leakage testing for containment isolation valves (normally performed under Type C tests), if not included under this program, is included under LRT programs for systems containing the isolation valves.

2. ***Preventive Action:*** No preventive actions are specified; the containment LRT program is a monitoring program.

3. ***Parameters Monitored or Inspected:*** The parameters to be monitored are leakage rates through containment shells; containment liners; and associated welds, penetrations, fittings, and other access openings.

4. ***Detection of Aging Effects:*** A containment LRT program is effective in detecting degradation of containment shells, liners, and components that compromise the containment pressure boundary, including seals and gaskets. While the calculation of leakage rates demonstrates the leak-tightness and structural integrity of the containment, it does not by itself provide information that would indicate that aging degradation has initiated or that the capacity of the containment may have been reduced for other types of loads, such as seismic loading. This would be achieved with the additional implementation of an acceptable containment inservice inspection program as described in XI.S1 and XI.S2.

5. ***Monitoring and Trending:*** Because the LRT program is repeated throughout the operating license period, the entire pressure boundary is monitored over time. The frequency of these tests depends on which option (A or B) is selected. With Option A, testing is performed on a

regular fixed time interval as defined in 10 CFR Part 50, Appendix J. In the case of Option B, the interval for testing may be increased on the basis of acceptable performance in meeting leakage limits in prior tests. Additional details for implementing Option B are provided in NRC Regulatory Guide 1.163 and NEI 94-01, Rev.0.

6. ***Acceptance Criteria:*** Acceptance criteria for leakage rates are defined in plant technical specifications. These acceptance criteria meet the requirements in 10 CFR Part 50, Appendix J, and are part of each plant's current licensing basis. The current licensing basis carries forward to the period of extended operation.

7. ***Corrective Actions:*** Corrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01. When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance, and appropriate corrective actions must be taken. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** When corrective actions are implemented to repair a condition that causes excessive leakage, confirmation by additional leak rate testing is performed to confirm that the deficiency has been corrected. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** Results of the LRT program are documented as described in 10 CFR Part 50, Appendix J, to demonstrate that the acceptance criteria for leakage have been satisfied. The test results that exceed the performance criteria must be assessed under 10 CFR 50.72 and 10 CFR 50.73. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** To date, the 10 CFR Part 50, Appendix J, LRT program has been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency must be consistent with plant-specific operating experience.

References

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2000.

10 CFR 50.72, *Immediate Notification Requirements for Operating Nuclear Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 1997.

10 CFR 50.73, *Licensee Event Report System,* Office of the Federal Register, National Archives and Records Administration, 1997.

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

NRC Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program,"*
U.S. Nuclear Regulatory Commission, September 1995.

XI.S5 MASONRY WALL PROGRAM

Program Description

Nuclear Regulatory Commission (NRC) IE Bulletin (IEB) 80-11, "Masonry Wall Design," and NRC Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," constitute an acceptable basis for a masonry wall aging management program (AMP). IEB 80-11 required the identification of masonry walls in close proximity to, or having attachments from, safety-related systems or components, and the evaluation of design adequacy and construction practice. NRC IN 87-67 recommended plant-specific condition monitoring of masonry walls and administrative controls to ensure that the evaluation basis developed in response to NRC IEB 80-11 is not invalidated by (1) deterioration of the masonry walls (e.g., new cracks not considered in the reevaluation), (2) physical plant changes such as installation of new safety-related systems or components in close proximity to masonry walls, or (3) reclassification of systems or components from non-safety-related to safety-related.

Important elements in the evaluation of many masonry walls during the NRC IEB 80-11 program included (1) installation of steel edge supports to provide a sound technical basis for boundary conditions used in seismic analysis and (2) installation of steel bracing to ensure containment of unreinforced masonry walls during a seismic event. Consequently, in addition to the development of cracks in the masonry walls, loss of function of the structural steel supports and bracing would also invalidate the evaluation basis.

The objective of the masonry wall program is to manage aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. Since the issuance of NRC IEB 80-11 and NRC IN 87-67, the NRC promulgated 10 CFR 50.65, the Maintenance Rule. Masonry walls may be inspected as part of the Structures Monitoring Program (XI.S6) conducted for the Maintenance Rule, provided the ten attributes described below are incorporated.

The attributes of an acceptable Masonry Wall Program are described below.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4.

2. ***Preventive Action:*** No specific preventive actions are required.

3. ***Parameters Monitored or Inspected:*** The primary parameter monitored is wall cracking that could potentially invalidate the evaluation basis.

4. ***Detection of Aging Effects:*** Visual examination of the masonry walls by qualified inspection personnel is sufficient. The frequency of inspection is selected to ensure there is no loss of intended function between inspections. The inspection frequency may vary from wall to wall, depending on the significance of cracking in the evaluation basis. Unreinforced masonry walls that have not been contained by bracing warrant the most frequent inspection, because the development of cracks may invalidate the existing evaluation basis.

5. ***Monitoring and Trending:*** Trending is not required. Monitoring is achieved by periodic examination for cracking.

6. ***Acceptance Criteria:*** For each masonry wall, the extent of observed cracking of masonry and degradation of steel edge supports and bracing is not to invalidate the evaluation basis. Corrective actions are taken if the extent of cracking and 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).

7. ***Corrective Actions:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Since 1980, masonry walls that perform an intended function have been systematically identified through licensee programs in response to NRC IEB 80-11, USI A-46, and 10 CFR 50.48. NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program, and provided recommendations for administrative controls and periodic inspection to ensure that the evaluation basis for each safety-significant masonry wall is maintained. Whether conducted as a stand-alone program or as part of structures monitoring for MR, a masonry wall AMP that incorporates the recommendations delineated in NRC IN 87-67 should ensure that the intended functions of all masonry walls within the scope of license renewal are maintained for the period of extended operation.

References

10 CFR 50.48, *Fire Protection,* Office of the Federal Register, National Archives and Records Administration, 2000.

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, 2000.

NRC Generic Letter 87-02, *Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46,* U.S. Nuclear Regulatory Commission, February 19,1987.

NRC IE Bulletin 80-11, *Masonry Wall Design,* U.S. Nuclear Regulatory Commission, May 8, 1980.

NRC Information Notice 87-67, *Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11,* U.S. Nuclear Regulatory Commission, December 31, 1987.

XI.S6 STRUCTURES MONITORING PROGRAM

Program Description

Implementation of structures monitoring under 10 CFR 50.65 (the Maintenance Rule) is addressed in Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, Rev. 2, and NUMARC 93-01, Rev. 2. These two documents provide guidance for development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function.

Because structures monitoring programs are licensee-specific, the Evaluation and Technical Basis for this aging management program (AMP) is based on the implementation guidance provided in Regulatory Guide 1.160, Rev. 2, and NUMARC 93-01, Rev. 2. Existing licensee-specific programs developed for the implementation of structures monitoring under 10 CFR 50.65 are acceptable for license renewal provided these programs satisfy the 10 attributes described below.

If protective coatings are relied upon to manage the effects of aging for any structures included in the scope of this AMP, the structures monitoring program is to address protective coating monitoring and maintenance.

Evaluation and Technical Basis

1. ***Scope of Program:*** The applicant specifies the structure/aging effect combinations that are managed by its structures monitoring program.

2. ***Preventive Action:*** No preventive actions are specified.

3. ***Parameters Monitored or Inspected:*** For each structure/aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Parameters monitored or inspected are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable). If necessary for managing settlement and erosion of porous concrete subfoundations, the continued functionality of a site de-watering system is to be monitored. The plant-specific structures monitoring program is to contain sufficient detail on parameters monitored or inspected to conclude that this program attribute is satisfied.

4. ***Detection of Aging Effects:*** For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.

5. ***Monitoring and Trending:*** Regulatory Position 1.5, "Monitoring of Structures," in RG 1.160, Rev. 2, provides an acceptable basis for meeting the attribute. A structure is monitored in accordance with 10 CFR 50.65 (a)(2) provided there is no significant degradation of the structure. A structure is monitored in accordance with 10 CFR 50.65 (a)(1) if the extent of degradation is such that the structure may not meet its design basis or, if allowed to continue uncorrected until the next normally scheduled assessment, may not meet its design basis.

6. ***Acceptance Criteria:*** For each structure/aging effect combination, the acceptance criteria are selected to ensure that the need for corrective actions will be identified before loss of intended functions. Acceptance criteria are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 provides an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. The plant-specific structures monitoring program is to contain sufficient detail on acceptance criteria to conclude that this program attribute is satisfied.

7. ***Corrective Actions:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Although in many plants structures monitoring programs have only recently been implemented, plant maintenance has been ongoing since initial plant operation. A plant-specific program that includes the attributes described above will be an effective AMP for license renewal.

References

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, 2000.

ACI Standard 349.3R-96, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute.

ANSI/ASCE 11-90, *Guideline for Structural Condition Assessment of Existing Buildings,* American Society of Civil Engineers.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1997.

NUMARC 93-01, Rev. 2, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Line-In/Line-Out Version),* Nuclear Energy Institute, April 1996.

XI.S7 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

Program Description

Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.127, Revision 1, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," describes an acceptable basis for developing an inservice inspection and surveillance program for dams, slopes, canals, and other water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The RG 1.127 program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures. The RG 1.127 program recognizes the importance of periodic monitoring and maintenance of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner.

RG 1.127 provides detailed guidance for the licensee's inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. Water-control structures covered by the RG 1.127 program include concrete structures; embankment structures; spillway structures and outlet works; reservoirs; cooling water channels and canals, and intake and discharge structures; and safety and performance instrumentation. RG 1.127 delineates current NRC practice in evaluating inservice inspection programs for water-control structures. The attributes of an acceptable aging management program (AMP) for license renewal are described below.

For plants not committed to RG 1.127, Revision 1, aging management of water-control structures may be included in the Structures Monitoring Program (XI.S6). However, details pertaining to water-control structures are to incorporate the attributes described herein.

Evaluation and Technical Basis

1. ***Scope of Program:*** RG 1.127 applies to water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The water-control structures included in the RG 1.127 program are concrete structures; embankment structures; spillway structures and outlet works; reservoirs; cooling water channels and canals, and intake and discharge structures; and safety and performance instrumentation.

2. ***Preventive Action:*** No preventive actions are specified; RG 1.127 is a monitoring program.

3. ***Parameters Monitored or Inspected:*** RG 1.127 identifies the parameters to be monitored and inspected for water-control structures. The parameters vary depending on the particular structure. Parameters to be monitored and inspected for concrete structures include cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage. Parameters to be monitored and inspected for earthen embankment structures include settlement, depressions, sink holes, slope stability (e.g., irregularities in alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features. Further details of parameters to be monitored and inspected for these and other water-control structures are specified in Section C.2 of RG 1.127.

4. ***Detection of Aging Effects:*** Visual inspections are primarily used to detect degradation of water-control structures. In some cases, instruments have been installed to measure the behavior of water-control structures. RG 1.127 indicates that the available records and readings of installed instruments are to be reviewed to detect any unusual performance or distress that may be indicative of degradation. RG 1.127 describes periodic inspections, to be performed at least once every five years. Similar intervals of five years are specified in ACI 349.3R for inspection of structures continually exposed to fluids or retaining fluids. Such intervals have been shown to be adequate to detect degradation of water-control structures before they have a significant effect on plant safety. RG 1.127 also describes special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls.

5. ***Monitoring and Trending:*** Water-control structures are monitored by periodic inspection as described in RG 1.127. In addition to monitoring the aging effects identified in Attribute (3) above, inspections also monitor the adequacy and quality of maintenance and operating procedures. RG 1.127 does not discuss trending.

6. ***Acceptance Criteria:*** Acceptance criteria to evaluate the need for corrective actions are not specified in RG 1.127. However, the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R-96 provides acceptance criteria (including quantitative criteria) for determining the adequacy of observed aging effects and specifies criteria for further evaluation . Although not required, plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R-96 are acceptable. Acceptance criteria for earthen structures such as dams, canals, and embankments are to be consistent with programs falling within the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC) or the U.S. Army Corps of Engineers.

7. ***Corrective Actions:*** RG 1.127 recommends that the licensee's inservice inspection and surveillance program include periodic inspections of water-control structures to identify deviations in structural conditions due to age-related deterioration and degradation from the original design basis. When findings indicate that significant changes have occurred, the conditions are to be evaluated. This includes a technical assessment of the causes of distress or abnormal conditions, an evaluation of the behavior or movement of the structure, and recommendations for remedial or mitigating measures. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Degradation of water-control structures has been detected, through RG 1.127 programs, at a number of nuclear power plants, and in some cases, it has required remedial action. No loss of intended functions has resulted from these occurrences. Therefore, it can be concluded that the inspections implemented in accordance with the guidance in RG 1.127 have been successful in detecting significant degradation before loss of intended function occurs.

NOTE: For dam inspection and maintenance, programs under the regulatory jurisdiction of FERC or the U.S. Army Corps of Engineers, continued through the period of extended operation, will be adequate for the purpose of aging management. For programs not falling under the regulatory jurisdiction of FERC or the U.S. Army Corps of Engineers, the staff will evaluate the effectiveness of the aging management program based on compatibility to the common practices of the FERC and Corps programs.

References

ACI Standard 349.3R-96, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute.

NRC Regulatory Guide 1.127, *Inspection of Water-Control Structures Associated with Nuclear Power Plants,* Revision 1, U.S. Nuclear Regulatory Commission, March 1978.

XI.S8 PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

Program Description

Proper maintenance of protective coatings inside containment (defined as Service Level I in Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev. 1) is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of strainers, which reduces flow through the sump/drain system. This has been addressed in NRC Generic Letter (GL) 98-04.

Maintenance of Service Level I coatings applied to carbon steel surfaces inside containment (e.g., steel liner, steel containment shell, penetrations, hatches) also serves to prevent or minimize loss of material due to corrosion. Regulatory Position C4 in RG 1.54, Rev. 1, describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program that can be credited for managing the effects of corrosion for carbon steel elements inside containment. The attributes of an acceptable program are described below.

A comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with RG 1.54, Rev. 0 or the American National Standards Institute (ANSI) standards (since withdrawn) referenced in RG 1.54, Rev. 0, and coatings maintenance programs described in licensee responses to GL 98-04, is also acceptable as an aging management program (AMP) for license renewal.

Evaluation and Technical Basis

1. ***Scope of Program:*** The minimum scope of the program is Service Level I coatings, defined in RG 1.54, Rev 1, as follows: "Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown."

2. ***Preventive Action:*** With respect to loss of material due to corrosion of carbon steel elements, this program is a preventive action.

3. ***Parameters Monitored or Inspected:*** Regulatory Position C4 in RG 1.54, Rev 1, states that "ASTM D 5163-96 provides guidelines that are acceptable to the NRC staff for establishing an in-service coatings monitoring program for Service Level I coating systems in operating nuclear power plants..." ASTM D 5163-96, subparagraph 9.2, identifies the parameters monitored or inspected to be "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

4. ***Detection of Aging Effects:*** ASTM D 5163-96, paragraph 5, defines the inspection frequency to be each refueling outage or during other major maintenance outages as needed. ASTM D 5163-96, paragraph 8, discusses the qualifications for inspection personnel, the inspection coordinator and the inspection results evaluator.
ASTM D 5163-96, subparagraph 9.1, discusses development of the inspection plan and the inspection methods to be used. It states, "A general visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through. After a walk-through, thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the Emergency Core Cooling System

(ECCS)." This subparagraph also addresses field documentation of inspection results. ASTM D 5163-96, subparagraph 9.5, identifies instruments and equipment needed for inspection.

5. ***Monitoring and Trending:*** ASTM D 5163-96 identifies monitoring and trending activities in subparagraph 6.2, which specifies a pre-inspection review of the previous two monitoring reports, and in subparagraph 10.1.2, which specifies that the inspection report should prioritize repair areas as either needing repair during the same outage or postponed to future outages, but under surveillance in the interim period.

6. ***Acceptance Criteria:*** ASTM D 5163-96, subparagraphs 9.2.1 through 9.2.6, 9.3 and 9.4, contain guidance for characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are identified for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D 5163-96, paragraph 11, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Repair work is prioritized as major or minor defective areas. A recommended corrective action plan is required for major defective areas, so that these areas can be repaired during the same outage, if appropriate.

7. ***Corrective Actions:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** NRC Generic Letter 98-04 describes industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. RG 1.54, Rev. 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service Level I coatings, and consequently an effective means to manage loss of material due to corrosion of carbon steel structural elements inside containment.

References

ASTM D 5163-96, *Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant,* American Society for Testing and Materials.

NRC Generic Letter 98-04, *Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,* U.S. Nuclear Regulatory Commission, July 14, 1998.

NRC Regulatory Guide 1.54, Rev. 0, *Quality Assurance Requirements for Protective Coatings Applied to Water-Controlled Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, June 1973.

NRC Regulatory Guide 1.54, Rev. 1, *Quality Assurance Requirements for Protective Coatings Applied to Water-Controlled Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, July 2000

XI.E1 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. Conductor insulation materials used in cables and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

The purpose of the aging management program described herein is to provide reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.

The program described herein is written specifically to address cables and connections at plants whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. This program, as described, can be thought of as a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. As such, this program does not apply to plants in which most cables are inaccessible.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables and connections covered by this aging management program are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

1. ***Scope of Program:*** This inspection program applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen.

2. ***Preventive Actions:*** This is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3. ***Parameters Monitored/Inspected:*** A representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination. The technical basis for the sample selected is to be provided.

4. ***Detection of Aging Effects:*** Conductor insulation aging degradation from heat, radiation, or moisture in the presence of oxygen causes cable and connection jacket surface anomalies. Accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years. This is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first inspection for license renewal is to be completed before the period of extended operation.

5. ***Monitoring and Trending:*** Trending actions are not included as part of this program because the ability to trend inspection results is limited. Although not a requirement, trending would provide additional information on the rate of degradation.

6. ***Acceptance Criteria:*** The accessible cables and connections are to be free from unacceptable, visual indications of surface anomalies, which suggest that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

7. ***Corrective Actions:*** All unacceptable visual indications of cable and connection jacket surface anomalies are subject to an engineering evaluation. Such an evaluation is to consider the age and operating environment of the component, as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of conductor insulation or connections. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When 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 cables or connections. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation.

References

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. P1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E2 ELECTRICAL CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

Program Description

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. Conductor insulation materials used in electrical cables may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument loop.

The purpose of the aging management program described herein is to provide reasonable assurance that the intended functions of electrical cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.

In this aging management program, routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation. When an instrumentation loop is found to be out of calibration during routine surveillance testing, trouble shooting is performed on the loop, including the instrumentation cable.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables covered by this aging management program are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

1. ***Scope of Program:*** This program applies to electrical cables used in circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation that are within the scope of license renewal.

2. ***Preventive Actions:*** This is a surveillance testing program and no actions are taken as part of this program to prevent or mitigate aging degradation.

3. ***Parameters Monitored/Inspected:*** The parameters monitored are determined from the plant technical specifications and are specific to the instrumentation loop being calibrated, as documented in the surveillance test procedure.

4. ***Detection of Aging Effects:*** Calibration provides sufficient indication of the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria related to instrumentation loop performance. The normal calibration frequency specified in the plant technical specifications provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function. The first tests for license renewal are to be completed before the period of extended operation.

5. ***Monitoring and Trending:*** Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Although not a requirement, test results that are trendable provide additional information on the rate of degradation.

6. ***Acceptance Criteria:*** Calibration readings are to be within the loop-specific acceptance criteria, as set out in the plant technical specifications surveillance test procedures.

7. ***Corrective Actions:*** Corrective actions such as recalibration and circuit trouble-shooting are implemented when an instrument loop is found to be out of calibration. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Operating experience has shown that a significant number of cable failures are identified through routine calibration testing. Changes in instrument calibration can be caused by degradation of the circuit cable and are one indication of potential electrical cable degradation.

References

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. P1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E3 INACCESSIBLE MEDIUM-VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to condensation and wetting in inaccessible locations, such as conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations. When an energized medium-voltage cable is exposed to wet conditions for which it is not designed, water treeing or a decrease in the dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure.

The purpose of the aging management program described herein is to provide reasonable assurance that the intended functions of inaccessible medium-voltage cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized will be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability. This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.

In this aging management program periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. In-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables covered by this aging management program are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

1. ***Scope of Program:*** This program applies to inaccessible (e.g., in conduit or direct buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. The moisture and voltage exposures

described as significant in these definitions, which are based on operating experience and engineering judgement, are not significant for medium-voltage cables that are designed for these conditions (e.g., continuous wetting and continuous energization is not significant for submarine cables).

2. ***Preventive Actions:*** Periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. Medium-voltage cables for which such actions are taken are not required to be tested since operating experience indicates that prolonged exposure to moisture and voltage are required to induce this aging mechanism.

3. ***Parameters Monitored/Inspected:*** In-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed.

4. ***Detection of Aging Effects:*** In-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years. This is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for license renewal are to be completed before the period of extended operation.

5. ***Monitoring and Trending:*** Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Although not a requirement, test results that are trendable provide additional information on the rate of degradation.

6. ***Acceptance Criteria:*** The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested.

7. ***Corrective Actions:*** 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 is to 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 is made as to whether the same condition or situation is applicable to other inaccessible, in-scope, medium-voltage cables. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address corrective actions.

8. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

10. ***Operating Experience:*** Operating experience has shown that XLPE or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. The formation and growth of water trees varies directly with operating voltage. Treeing is much less prevalent in 4kV cables than those operated at 13 or 33kV. Also, minimizing exposure to moisture minimizes the potential for the development of water treeing. As additional operating experience is obtained, lessons learned can be used to adjust the program, as needed.

References

EPRI TR-103834-P1-2, *Effects of Moisture on the Life of Power Plant Cables,* Electric Power Research Institute, Palo Alto, CA, August 1994.

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. P1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

APPENDIX

QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

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QUALITY ASSURANCE FOR AGING MANAGEMENT PROGRAMS

The license renewal applicant must demonstrate that the effects of aging on structures and components subject to an aging management review (AMR) will be adequately managed to ensure that their intended functions will be maintained consistent with the current licensing basis (CLB) of the facility for the period of extended operation. Therefore, those aspects of the AMR process that affect the quality of safety-related structures, systems, and components are subject to the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. For non-safety-related structures and components subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used to address the elements of corrective actions, confirmation process, and administrative controls on the following bases:

- Criterion XVI of 10 CFR Part 50, Appendix B, requires that measures be established to ensure that conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures must be implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude repetition. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented must be documented and reported to appropriate levels of management.

- Because Criterion XVI of 10 CFR Part 50, Appendix B, requires that measures be taken to preclude repetition of significant conditions adverse to quality, follow-up actions must be taken to verify effective implementation of the proposed corrective action. This verification comprises the confirmation process element for aging management programs for license renewal. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition monitoring program (ultrasonic inspection) to verify that corrosion is indeed insignificant. When corrective actions are necessary for significant conditions, follow-up activities are to confirm that the corrective actions implemented are effective in preventing recurrence.

- Administrative controls are the provisions associated with organization and management, policies, orders, instructions, procedures, record keeping, and designations of authority and responsibility that are necessary to ensure operation of the facility in a safe manner. 10 CFR 50.34(b)(6)(ii) and 10 CFR 50.36(c)(5) require that nuclear power plant license applicants include in the final safety analysis report information on the managerial and administrative controls to be used to ensure safe operation. 10 CFR 50.34(b)(6)(ii) and 10 CFR 50.36(c)(5) also stipulate that Appendix B to 10 CFR Part 50 sets forth the requirements for these managerial and administrative controls. Accordingly, programs consistent with the requirements of 10 CFR Part 50, Appendix B, also satisfy the administrative controls element necessary for aging management programs (AMPs) for license renewal.

Notwithstanding the suitability of its provisions to address quality-related aspects of the AMR process for license renewal, 10 CFR Part 50, Appendix B, covers only safety-related structures, systems, and components. Therefore, absent a commitment by the applicant to expand the scope of its 10 CFR Part 50, Appendix B, QA program to include non-safety-related structures and components subject to an AMR for license renewal, the AMPs applicable to such structures and components are to provide alternative means to address corrective actions, confirmation process, and administrative controls. Such alternate means would be subject to review by NRC on a case-by-case basis.

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The Generic Aging Lessons Learned (GALL) report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the extended period of operation. The evaluation results documented in the GALL report indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components for license renewal without change. The GALL report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL report in a license renewal application to demonstrate that the programs at the applicant's facility correspond to those reviewed and approved in the GALL report and that no further staff review is required. The focus of the staff review is on the augmented existing programs for license renewal. The incorporation of the GALL report information into the NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," as directed by the Commission, should improve the efficiency of the license renewal process.

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