10 CFR 54.21(b)

APS

A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear Generating Station

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102-06100-DCM/GAM
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ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

**Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528, 50-529 and 50-530
Annual Update to the PVNGS License Renewal Application, and License Renewal Application Amendment No. 3**

By letter no. 102-05937, dated December 11, 2008, as supplemented by letter no. 102-05989, dated April 14, 2009, Arizona Public Service Company (APS) submitted a license renewal application (LRA) for PVNGS Units 1, 2, and 3. As required by 10 CFR 54.21(b), each year following submittal of the license renewal application, an amendment to the renewal application must be submitted that identifies any change to the current licensing basis (CLB) of the facility that materially affects the contents of the license renewal application (LRA), including the Final Safety Analysis Report (FSAR) supplement.

Enclosure 1 identifies PVNGS LRA changes that are being made to (1) reflect CLB changes, (2) update operating experience, (3) reflect completed enhancements/ commitments, and (4) incorporate improvements to the LRA. Enclosure 2 contains the affected LRA pages with changes shown as electronic mark-ups (deletions crossed out and insertions underlined). As a reviewer aid, all pages of the Appendix B aging management program section are provided, including unchanged pages, when there is a change on any of the pages in that section.

Two new commitments and changes to seven existing commitments are contained in the changes to LRA Table A4-1 in Enclosure 2.

Should you need further information regarding this Submittal, please contact Russell A. Stroud, Licensing Section Leader, at (623) 393-5111.

A138
NRR

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

Executed on 12/7/09
(date)

Sincerely,

D.C. Mims

DCM/RAS/GAM

Enclosures: 1. Description of Changes for Palo Verde Nuclear Generating Station License Renewal Application Amendment No. 3

2. Palo Verde Nuclear Generating Station License Renewal Application Amendment No. 3

cc:	E. E. Collins Jr.	NRC Region IV Regional Administrator
	J. R. Hall	NRC NRR Project Manager
	R. I. Treadway	NRC Senior Resident Inspector for PVNGS
	L. M. Regner	NRC License Renewal Project Manager

ENCLOSURE 1

Description of Changes for Palo Verde Nuclear Generating Station License Renewal Application Amendment No. 3

Changes Related to Aging Management Programs (AMPs)

AMP XI.M1 (B2.1.1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Affected LRA Section

B2.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"

Reason for Change

Update operating experience (OE).

AMP XI.M2 (B2.1.2) Water Chemistry

Affected LRA Sections

A1.2, "Water Chemistry"
B2.1.2, "Water Chemistry"

Reason for Change

Update OE and EPRI guideline revision references.

AMP XI.M10 (B2.1.4) Boric Acid Corrosion

Affected LRA Sections

A1.4, "Boric Acid Corrosion"
B2.1.4," Boric Acid Corrosion"

Reason for Change

Update program description to include a direct reference to the two nickel alloy AMPs instead of Regulatory Issue Summary (RIS) 2003-13.

AMP XI.M11A (B2.1.5) Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

Affected LRA Section

B2.1.5, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors"

Reason for Change

Update OE to reflect the new reactor vessel head installed in Unit 2 containing Alloy 690 components, and add a commitment to replace the Unit 1 and Unit 3 heads.

AMP XI.M17 (B2.1.6) Flow-Accelerated Corrosion

Affected LRA Sections

A1.6, "Flow-Accelerated Corrosion"
Table A4-1, Item 8, "License Renewal Commitments"
B2.1.6, "Flow-Accelerated Corrosion"

Reason for Change

Delete the enhancement referring to chromium content of replacement piping. NUREG-1801 recommends replacing piping with flow-accelerated corrosion (FAC)-resistant piping. The PVNGS FAC program has a provision that replacement piping should be FAC-resistant. The deleted enhancement was to strengthen the requirement for obtaining material certification for the chromium content in the piping. This was a level of detail not necessary for the LRA.

Update OE.

AMP XI.M19 (B2.1.8) Steam Generator Tube Integrity

Affected LRA Section

B2.1.8, "Steam Generator Tube Integrity"

Reason for Change

Update OE.

AMP XI.M20 (B2.1.9) Open-Cycle Cooling Water System

Affected LRA Sections

A1.9, "Open-Cycle Cooling Water System"
Table A4-1, Item 11, "License Renewal Commitments"
B2.1.9, "Open-Cycle Cooling Water System"

Reason for Change

Update to reflect procedure changes that addressed the enhancement regarding the conduct of heat exchanger and piping inspections using NDE techniques.

AMP XI.M26 (B2.1.12) Fire Protection

Affected LRA Sections

A1.12, "Fire Protection"
Table A4-1, Item 14, "License Renewal Commitments"
B2.1.12, "Fire Protection"

Reason for Change

Update to reflect (1) procedure changes that addressed the enhancement regarding visual inspection of the fuel supply line to detect degradation and (2) Technical Requirements Manual changes related to the functional testing of halon and CO_2 dampers.

AMP XI.M30 (B2.1.14) Fuel Oil Chemistry

Affected LRA Sections

A1.14, "Fuel Oil Chemistry"
Table A4-1, Item 16, "License Renewal Commitments"
B2.1.14, "Fuel Oil Chemistry"

Reason for Change

Clarify the station blackout generator (SBOG) fuel oil storage tanks include both the fuel oil storage tank and the SBOG skid fuel tanks.

AMP XI.M33 (B2.1.17) Selective Leaching of Materials

Affected LRA Sections

3.3.2.1.3, "Essential Cooling Water System"
A1.17, "Selective Leaching of Materials"
Table A4-1, Item 19, "License Renewal Commitments"
B2, Table B2 List of Aging Management Programs
B2.1.17, "Selective Leaching of Materials"

Reason for Change

Remove reference to selective leaching as an applicable AMP from LRA Section 3.3.2.1.3, "Essential Cooling Water System," due to the heat exchanger tubes being constructed of Admiralty Brass that are not susceptible to selective leaching.

Update to reflect procedure changes that addressed the implementation of the Selective Leaching of Materials program.

AMP XI.M34 (B2.1.18) Buried Piping and Tanks Inspection

Affected LRA Sections

3.3.2.1.25, "Service Gases (N2 and H2) System"
Table 3.3.2-25, "Auxiliary Systems – Summary of Aging Management Evaluation – Service Gases (N2 and H2) System"
A1.18, "Buried Piping and Tanks Inspection"
B2.1.18, "Buried Piping and Tanks Inspection"

Reason for Change

Add piping segments for the condensate storage system and service gas system to the scope of the buried piping and tanks inspection aging management program. The buried piping segments of these systems were incorrectly assessed to be routed through a tunnel, thus were not originally included in the scope of this AMP.

AMP XI.M35 (B2.1.19) One-time Inspection of ASME Code Class 1 Small-Bore Piping

Affected LRA Sections

LRA A1.19, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping"
Table A4-1, Item 21, "License Renewal Commitments"
B2, Table B2 List of Aging Management Programs
B2.1.19, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping"

Reason for Change

Update to reflect that PVNGS no longer uses a Risk-Informed ISI program and is therefore proposing a new program for a One-time Inspection of ASME Class I small-bore piping.

Update OE.

AMP XI.M38 (B2.1.22) Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Affected LRA Sections

B2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"

Reason for Change

Revise program exception to include cracking of stainless steel and surface examinations in addition to volumetric exams for cracking of stainless steel components.

AMP XI.M39 (B2.1.23) Lubricating Oil Analysis

Affected LRA Sections

B2.1.23, "Lubricating Oil Analysis"

Reason for Change

Incorporate changes to clarify lubricating oil sampling methods and update OE.

AMP XI.E2 (B2.1.25) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Affected LRA Sections

A1.25, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"
Table A4.1, Item 27, "License Renewal Commitments"
B2.1.25, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"

Reason for Change

Update to reflect procedure changes that addressed the enhancement associated with plant loop calibration procedures, and clarify the remaining enhancement for the evaluation of calibration results.

AMP XI.E3 (B2.1.26) Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Affected LRA Sections

B2.1.26, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"

Reason for Change

Update OE.

AMP XI.E5 (B2.1.37) Fuse Holders

Affected LRA Sections

2.5.1.3, "Fuse Holders (not part of larger assembly)"
2.5.2, Table 2.5-1, "Electrical and I&C Component Groups Requiring Aging Management Review"
3.6.1, "Introduction"
3.6.2.1.10, "Fuse Holders"

3.6.2, Table 3.6.1, "Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical and Instrument and Controls"
3.6.2, Table 3.6.2-1,"Electrical and Instrument and Controls – Summary of Aging Management Evaluation – Electrical Components"
A1.37, "Fuse Holders"
A4-1, Item 50 (new), "License Renewal Commitments"
B1.5, "Aging Management Programs"
B2, Table B2 List of Aging Management Programs
B2.1.37, "Fuse Holders"

Reason for Change

Add a new aging management program for fuse holders because PVNGS has identified two fuse boxes in each unit that are not located inside active devices.

Plant-Specific AMP (B2.1.34) Nickel Alloy Aging Management Program

Affected LRA Sections

A1.34, "Nickel Alloy Aging Management Program"
A4-1, Item 51 (new), "License Renewal Commitments"
B2.1.34, "Nickel Alloy Aging Management Program"

Reason for Change

Update to include MRP-139, Revision 1 (EPRI Report 1015009 replaced 1010087).

Update to reflect the completion of Unit 3 weld overlays.

Update to reflect the installation of the new Unit 2 reactor vessel head, and add a commitment to replace the Unit 1 and Unit 3 reactor vessel heads. All components penetrating the new heads and welds, including the head vent, are replaced with Alloy 690.

Changes to Time-Limited Aging Analyses

(Section 4.3) Metal Fatigue Analysis, Fatigue Aging Management Program

Affected LRA Section

4.3.1.4, "Present and Projected Status of Monitored Locations"
4.3.1.5, Table 4.3-3,"APS Fatigue Cycle Count Verification (Composite Worst-Case Unit), and Projections," Item Nos. 19, 21, 32, and 33
4.3.2.13, "Absence of TLAAs in Evaluations of Effects of Vibration on the Unit 1 Train A Shutdown Cooling System Suction Line Fatigue Analysis, and of Vibration Limits Established for its Isolation Valve Actuator"

Reason for Change

Update to reflect completion of a review of the Unit 3 plant transient data.

Revise Table 4.3-3 (Transients 19, 21, 32 and 33) to be consistent with the projection methodology. A minor clarification was made to Section 4.3.2.13.

AMP X.M1 (B3.1) Metal Fatigue of Reactor Coolant Pressure Boundary

Affected LRA Sections

4.3.1.5, "Program Scope, Action Limits, and Corrective Actions"
B3.1, "Metal Fatigue of Reactor Coolant Pressure Boundary"

Reason for Change

Revise Section 4.3.1.5, Corrective Action Limits and Corrective Actions, and incorporate minor changes and clarification edits.

ENCLOSURE 2

Palo Verde Nuclear Generating Station
License Renewal Application
Amendment No. 3

PVNGS LRA Amendment No. 3
Affected Pages

LRA Section	AMP	Page Nos.
2.5.1.3	XI.E5	2.5-2, 2A
2.5.2, Table 2.5-1	XI.E5	2.5-6
3.3.2.1.3	XI.M33	3.3-7
3.3.2.1.25	XI.M34	3.3-29
3.3.2, Table 3.3.2-25	XI.M34	3.3-215
3.6.1	XI.E5	3.6-1
3.6.2.1.10	XI.E5	3.6-10A
3.6, Table 3.6.1	XI.E5	3.6-15, 17
3.6.2, Table 3.6.2-1	XI.E5	3.6-23
4.3.1.4	Metal Fatigue	4.3-10
4.3.1.5, Table 4.3-3	Metal Fatigue	4.3-14, 15, 21
4.3.1.5	X.M1	4.3-23
4.3.2.13	Metal Fatigue	4.3-70
A1.2	XI.M2	A-2, 3
A1.4	XI.M10	A-3
A1.6	XI/M17	A-4
A1.9	XI.M20	A-6
A1.12	XI.M26	A-7
A1.14	XI.M30	A-8, 9
A1.17	XI.M33	A-10, 11
A1.18	XI.M34	A-11
A1.19	XI.M35	A-11, 11A
A1.25	XI.E2	A-15
A1.34	Nickel Alloy	A-19
A1.37	XI.E5	A-20
A4, Table A4-1 No.8	XI.M17	A-43
A4, Table A4-1 No.11	XI.M20	A-43
A4, Table A4-1 No.14	XI.M26	A-44
A4, Table A4-1 No.16	XI.M30	A-46
A4, Table A4-1 No.19	XI.M33	A-48

LRA Section	AMP	Page Nos.
A4, Table A4-1 No.21	XI.M35	A-49
A4, Table A4-1 No. 27	XI.E2	A-51
A4, Table A4-1 No. 50	XI.E5	A-59
A4, Table A4-1 No. 51	Nickel Alloy	A-59
B1.5	XI.E5	B-5
B2	XI.E5, M33, M35	B-9, 10
B2.1.1	XI.M1	B-12, 13
B2.1.2	XI.M2	B-14, 15, 16, 17
B2.1.4	XI.M.10	B-19, 20
B2.1.5	XI.M11A	B-21, 22, 23, 24
B2.1.6	XI.M17	B-25, 26
B2.1.8	XI.M18	B-30, 31, 32, 33
B2.1.9	XI.M20	B-34, 35, 36
B2.1.12	XI.M26	B-45, 46, 47
B2.1.14	XI.M30	B-51, 52
B2.1.17	XI.M33	B-58, 59
B2.1.18	XI.M34	B-60, 61
B2.1.19	XI.M35	B-62, 63
B2.1.22	XI.M38	B-67, 68
B2.1.23	XI.M39	B-69, 70, 71
B2.1.25	XI.E2	B-74, 75
B2.1.26	XI.E3	B-76, 77
B2.1.34	Nickel Alloy	B-97, 98, 99, 100, 101, 102, 103, 104, 105 106, 107, 108, 109, 109A, 109B.
B2.1.37	XI.E5	B-113A, 113B
B3.1	X.M1	B-114, 115, 116, 117, 118, 119

  - Bus Insulation and insulators

- Penetrations Electrical
- Switchyard Bus and Connections
- Terminal Block
- Transmission Conductors and Connections
- Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements
- Grounding conductors
- Cable Tie Wraps

License renewal drawing (LR-PVGS-ELEC-E-MAA-001) was created based on the electrical one-line diagram.

2.5.1 Electrical Component Groups

2.5.1.1 Connections (metallic parts)

The cable connections component type includes the metallic portions of cable connections that are located within passive and active equipment.

The function of the cable connections (metallic parts) is to electrically connect specified sections of an electrical circuit to deliver voltage, current or signals.

2.5.1.2 Connectors

The connector component type includes the connector contacts for electrical connectors exposed to borated water leakage. The function of the connectors is to electrically connect specified sections of an electrical circuit to deliver voltage, current or signals.

2.5.1.3 Fuse Holders (not part of larger assembly)

~~All fuse holders including those installed for electrical penetration protection are part of larger assemblies and are managed as part of the active component.~~The fuse holder type includes both the insulation and metallic clamp of in-scope fuse holders that are not part of larger assemblies (active equipment).

The function of the fuse holder insulation is to electrically insulate sections of an electrical circuit from adjacent circuits and enclosures. The fuse holder insulating material of in-scope fuse holders that are not part of a larger assembly is addressed with insulated cables and connections.

The function of the fuse holder metallic clamp is to maintain electrical continuity between specified sections of an electrical circuit to deliver voltage, current, or signals.

2.5.1.4 High Voltage Insulators

The high voltage insulators within the scope of license renewal are those associated with the power feeds from the switchyard to the plant that are used to connect the plant to the offsite power. These power feeds are required for the restoration of offsite power to meet the station blackout requirements.

Table 2.5-1 Electrical and I&C Component Groups Requiring Aging Management Review

Component Type	Intended Function
Cable Connections (Metallic Parts)	Electrical Continuity
Connector	Electrical Continuity
High Voltage Insulator	Insulate (Electrical) Non-S/R Structural Support
Insulated Cable and Connections	Electrical Continuity Insulate (Electrical)
Metal Enclosed Bus (Bus/Connections)	Electrical Continuity
Metal Enclosed Bus (Enclosure)	Expansion/Separation Non-S/R Structural Support
Metal Enclosed Bus (Insulation/Insulators)	Insulate (Electrical)
Penetrations Electrical	Electrical Continuity Insulate (Electrical)
Switchyard Bus and Connections	Electrical Continuity
Terminal Block	Insulate (Electrical)
Transmission Conductors and Connections	Electrical Continuity
Fuse Holders (Not part of a larger assembly)	Electrical Continuity Insulate (Electrical)

- External Surfaces Monitoring Program (B2.1.20)
- Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components (B2.1.22)
- One-Time Inspection (B2.1.16)
- Open-Cycle Cooling Water System (B2.1.9)
- ~~Selective Leaching of Materials (B2.1.17)~~
- Water Chemistry (B2.1.2)

3.3.2.1.4 Essential Chilled Water System

Materials

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

- Carbon Steel
- Cast Iron
- Copper Alloy
- Copper Alloy (Zinc >15%)
- Glass
- Nickel Alloys
- Stainless Steel

Environment

The essential chilled water system components are exposed to the following environments:

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

Aging Effects Requiring Management

The following essential chilled water system aging effects require management:

- Loss of material
- Loss of preload

- Fuel Oil Chemistry (B2.1.14)
- One-Time Inspection (B2.1.16)

3.3.2.1.25 Service Gases (N2 and H2) System

Materials

The material of construction for the service gases (N2 and H2) systems component types is:

- Carbon Steel
- Stainless Steel

Environment

The service gases (N2 and H2) systems component types are exposed to the following environments:

- Buried
- Dry Gas
- Plant Indoor Air

Aging Effects Requiring Management

The following service gases (N2 and H2) system aging effect requires management:

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management program manages the aging effects for the service gases (N2 and H2) systems component types:

- Bolting Integrity (B2.1.7)
- Buried Piping and Tanks Inspection (B2.1.18)
- External Surfaces Monitoring Program (B2.1.20)

3.3.2.1.26 Gaseous Radwaste System

Materials

The materials of construction for the gaseous radwaste system component types are:

- Carbon Steel
- Glass
- Stainless Steel

Table 3.3.2-25 Auxiliary Systems – Summary of Aging Management Evaluation – Service Gases (N2 and H2) System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	PB	Stainless Steel	Dry Gas (Int)	None	None	VII.J-18	3.3.1.98	A
Valve	PB	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
Piping	PB	Carbon Steel	Buried (Ext)	Loss of material	Buried Piping and Tanks Inspection (B2.1.18)	VII.G-25	3.3.1.19	B

Notes for Table 3.3.2-25:

Standard Notes:

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

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

Plant Specific Notes:

None

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 Introduction

Section 3.6 provides the results of the aging management reviews for those component types identified in Section 2.5, Scoping and Screening Results – Electrical and Instrument and Control Systems, subject to aging management review. The electrical component types subject to aging management review are discussed in the following sections:

- Connections (metallic parts) (Section 2.5.1.1)
- Connector (Section 2.5.1.2)
- Fuse Holders (Not part of a larger assembly) (Section 2.5.1.3)
- High Voltage Insulators (Section 2.5.1.4)
- Insulated Cable and Connections (Section 2.5.1.5) (includes the following):
  - Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
  - Electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance
  - Inaccessible Medium-Voltage Electrical Cables not subject to 10 CFR 50.49 EQ requirements
- Metal Enclosed Bus (Section 2.5.1.6) (includes the following):
  - Bus bar and connections
  - Bus enclosure
  - Bus Insulation and insulators
- Penetrations Electrical (Section 2.5.1.7)
- Switchyard Bus and Connections (Section 2.5.1.8)
- Terminal Block (Section 2.5.1.9)
- Transmission Conductors and Connections (Section 2.5.1.10)

Table 3.6.1, Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components, provides the summary of the programs evaluated in NUREG-1801 that are applicable to component types in this Section. Table 3.6.1 uses the format of Table 1 described in Section 3.0.

3.6.2.1.10 Fuse Holders

Materials

The materials of construction for fuse holders are:

- Copper Alloy
- Various Insulation Materials (Electrical)

Environment

Fuse holders are exposed to the following environment

- Plant Indoor Air

Aging Effects Requiring Management

The following fuse holder aging effects require management:

- Fatigue

Aging Management Programs

The following aging management program manages the aging effects for the fuse holders.

- Fuse Holders (B2.1.37)

Table 3.6.1 Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1.04	Conductor insulation for inaccessible medium voltage (2 kV to 35 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 EQ Requirements (B2.1.26)	No	Consistent with NUREG-1801.
3.6.1.05	Connector contacts for electrical connectors exposed to borated water leakage	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion (B2.1.4)	No	Consistent with NUREG-1801.
3.6.1.06	Fuse Holders (Not Part of a Larger Assembly): Fuse holders – metallic clamp	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders (B2.1.37)	No	~~Not applicable. All fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies, so the applicable NUREG-1801 lines were not used.~~ Consistent with NUREG-1801.
3.6.1.07	Metal enclosed bus - Bus/connections	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus (B2.1.36)	No	Consistent with NUREG-1801.

Table 3.6.1 Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1.12	Transmission conductors and connections, Switchyard bus and connections	Loss of material due to wind induced abrasion and fatigue, Loss of conductor strength due to corrosion, Increased resistance of connection due to oxidation or loss of preload	A plant-specific aging management program is to be evaluated.	Yes	Exception to NUREG-1801. Aging effect in NUREG-1801 for this material and environment combination is not applicable. See further evaluation in Section 3.6.2.2.3.
3.6.1.13	Cable Connections – Metallic parts	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B2.1.35)	No	Consistent with NUREG-1801.
3.6.1.14	Fuse Holders (Not Part of a Larger Assembly) Insulation material	None	None	NA – No AEM or AMP	~~Not applicable. All fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies, so the applicable NUREG-1801 lines were not used.~~ Consistent with NUREG-1801.

Table 3.6.2-1 – Electrical and Instrument and Controls – Summary of Aging Management Evaluation – Electrical Components

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Transmission Conductors and Connections	EC	Aluminum Conductor Steel Reinforced	Atmosphere/ Weather (Ext)	None	None	VI.A-16	3.6.1.12	I, 2
Fuse Holder	EC	Copper Alloy	Plant Indoor Air (Ext)	Fatigue	Aging Management Program for Fuse Holders	VI.A-8	3.6.1.06	A
Fuse Holder	IN	Various Insulation Material (Electrical)	Plant Indoor Air (Ext)	None	None	VI.A-7	3.6.1.14	A

Notes for Table 3.6.2-1:

Standard Notes:

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

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

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

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

J Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1 See further evaluation 3.6.2.2.2

2 See further evaluation 3.6.2.2.3

3 PVNGS will use the Metal Enclosed Bus program (B2.1.36) to manage the aging effects for all metal enclosed bus components.

1995 revision of the cycle count procedure, transients were recorded on a case-by-case basis and were added to the 25% accumulation assumed in 1995.

APS Fatigue Cycle Count Verification

The goal of the APS fatigue cycle count verification was to reduce the uncertainty created by the 25% accumulation assumed in 1995.

Scope

Transients adding significant fatigue to components were included in the APS transient recount. Transients not contributing significantly to fatigue were not included in the APS transient recount. The transients not included in the recount are retained in the composite worst-case unit accumulation, including the 25% accumulation assumed in 1995.

Recount Method

Unit 1 was the prototype Combustion Engineering System 80 plant. Due to a lack of operating experience, early Unit 1 operation included tests and events that did not generally occur as frequently in subsequent units. A cycle count record from Unit 1 should therefore be a conservative estimate for Unit 2 and Unit 3. However, Unit 1 had a 460-day outage, with Unit 2 running, but during which Unit 2 experienced many startup-shutdown transients. Therefore, APS has created a composite worst-case (composite-unit) envelope including only the highest accumulation of each transient experienced among the three units from 1985 through 2005.

APS performed a best effort retrieval of the transient count data recorded from 1985 through 1995 (the "APS transient recount"). Sources for this effort included (1) NRC Information Reports for all three units, (2) Unit 1 control room logs from 1985 through 1995, (3) Unit 2 control room logs from 1986 through 1995, (4) Unit 3 control room logs from 1987 through 1995, and (~~4~~5) interviews with plant personnel~~(for Unit 1 only)~~. The result of this data retrieval is the "worst-case APS transient recount from 1985 through 1995." ~~Unit 3 control room log data was not reviewed. Unit 3 did not experience the early operation complications of Unit 1 and 2, therefore the Unit 1 and 2 composite worst-case transient recount (including Unit 3 NRC Information Report data) is expected to bound the transients experienced by Unit 3.~~

The 25% accumulation assumed in 1995 was subtracted from the totals recorded through 2005 in the cycle count procedure to obtain the accumulation from 1996 through 2005 for each transient. This accumulation from 1996 through 2005 was then added to the worst-case APS transient recount from 1985 through 1995 to obtain the composite worst-case unit accumulation of cycles from 1985 to 2005, for each transient.

Transient Projections

A yearly accumulation rate must be calculated in order to accurately project transient accumulation through the period of extended operation. The yearly accumulation rate was calculated by dividing the composite-unit accumulation from 1985 through 2005 by the least

Table 4.3-3 - APS Fatigue Cycle Count Verification (Composite Worst-Case Unit), and Projections[1, 2]

	Limiting Number of Events (Table 4.3-2)	Transient[3] Transient Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Recount (1985-1995)	Composite Worst-Case Unit Accumulation (1985-2005)[4]	Accumulation Rate (per year)[5]	Projected to 40 years[6]	Projected to 60 years[7]
		(1985-1995) 25% Assumed[8]	Worst-Case (1985-2005) Incl. 25% Assumed					
18. Safety Injection Check Valve Test[17]	160	NR	NR	0	0	[18]	1	1
19. High Pressure Safety Injection Header Check Valve Test	40	NR	NR	~~1~~ 0	~~3[13]~~ 0	~~0.13~~ [18]	~~5~~ 1	~~8~~ 1
20. Turbine Roll Test at Hot Standby	10	NR	NR	3	3	[18]	4	4
21. Auxiliary Spray During Cooldown	500	NR	NR	~~NC~~ 63	~~63~~ 142	~~6.88~~ 7.88[13]	~~215~~ 315	~~352~~ 473
22. Initiation of Shutdown Cooling	500	125	148	NC	148[14]	8.22	329	494
Upset Events								
23. RCP Coastdown at 100% Power	10	NR	NR	NC	NC	0.14 [19]	4	6
24. Reactor Trip	50	13	19	28	34	1.89	**76**[16]	**114**[16]
25. Loss of Reactor Coolant Flow	40	10	12	2	4	0.22	9	14
26. Loss of Load (Load Reduction from 100 to 15% Power)	40	10	11	13	14	0.78	32	**47**[16]

Table 4.3-3 - APS Fatigue Cycle Count Verification (Composite Worst-Case Unit), and Projections[1, 2]

	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Recount (1985-1995)	Composite Worst-Case Unit Accumulation (1985-2005)[4]	Accumulation Rate (per year)[5]	Projected to 40 years[6]	Projected to 60 years[7]
		(1985-1995) 25% Assumed[8]	Worst-Case (1985-2005) Incl. 25% Assumed					
27. Operational Basis Earthquake	200	NR	0	NC	0[10]	[18]	20[20]	20[20]
28. Inadvertent CEA Drop	40	10	11	5	6	0.33	14	20
29. Inadvertent CEA Withdrawal	40	10	11	0	1	0.06	3	4
30. Loss of Charging	200	25	27	5	7	0.39	16	24
31. Loss of Letdown and Recovery	300	210	213	17	20	1.11	45	67
32. Extended Loss of Letdown	800	NR [26]	~~200~~ 64[26]	~~34~~ NC	~~234~~ 64[26]	~~13.00~~ 3.56	~~520~~ 143	~~780~~ 214
33. Depressurization by Spurious Actuation of Pressurizer Spray Control Valve at 100% Power (Main & Aux. Spray)	40	10	11	~~0~~ 1	~~1~~ 2	~~0.06~~ 0.11	~~3~~ 5	~~4~~ 7
34. Partial Loss of Condenser Cooling at 100% Power	40	10	11	NC	11[14]	0.61	25	37

[10] Transient was counted by the cycle count procedure since initial plant startup, therefore no cycles were assumed. The "Composite Worst-Case Unit Accumulation" is the same as the "(1985-2005)" procedure count.

[11] Transients not recorded in the 73ST-9RC02 procedure are marked as "NR."

[12] Transients 5 and 6 were not counted separately in the cycle count procedure; only 10% power increases were recorded in the procedure. Due to an incomplete transient description, the procedure only included power changes between 90% and 100% power.

[13] Transient was not separately counted in the cycle count procedure, therefore the "Accumulation Rate" was calculated by taking the APS recount number and dividing by the least number of years in operation up to 1995 (Unit 3 operating period of 8 years) to determine the worst-case number of events experienced per year. The "Composite Worst-Case Unit Accumulation" was calculated by multiplying the calculated "Accumulation Rate" by 10 years (1995 to 2005) and adding the result to the APS recount.

[14] Transient event does not contribute significantly to fatigue and is not counted by the Fatigue Management Program. The "Composite Worst-Case Unit Accumulation" includes the 25% accumulation assumed in 1995.

[15] The "Composite Worst-Case Unit Accumulation" for Transient 16, "Unbolting/Bolting of RC Pump Casing Studs," is a conservative estimate for a worst-case stud, extracted by review of maintenance work orders, for the APS fatigue cycle count verification.

[16] The APS fatigue cycle count verification resulted in higher than expected projected values for ~~T~~transients 16, 17, 24, 26, 36, 40, and 50. These transients will require re-evaluation or other corrective actions when action limits are reached.

[17] Transient 18, "Safety Injection Check Valve Test" is not counted specifically because the check valve test is performed during a stage of startup at normal heatup pressure and temperature, resulting in no significant fatigue accumulation.

[18] Transient is not expected to occur; therefore no "Accumulation Rate" value calculated for this transient. However, at least one occurrence was assumed to occur during the period of extended operation.

[19] Transient has no to-date accumulation through 2005. The "Accumulation Rate" was determined by dividing the design basis number of transient events by 40 years and multiplying the result by the percentage of years left in the design basis (22/40).

[20] One Operational Basis Earthquake is equal to 20 transient cycles.

[21] UFSAR numbers of 5 events from 100% power; 40 events from an unspecified power level.

[22] Transient 39, "Seismic Event up to and including One-Half of the Safe Shutdown Earthquake, at 100% Power" is not counted specifically because it is included in the count for transient 27, "Operating Basis Earthquake."

[23] Transient 42, "Loss of Feedwater Flow (to S/G)" is not counted specifically because it is included in the counts for transients 47, 48, and 49.

[24] Transient 53, "Inadvertent Closure of all MFIVs at 100% Power" is not counted specifically because it is a duplicate of transient 49, "MFIV Closures due to Loss of Air at 100% Power".

[25] Transients 60 and 61, "LPSI and HPSI Pump Tests" are not listed as Licensing and Design Basis Transients. These are quarterly tests that add significant fatigue to the pumps and components upstream of the isolation valves.

[26] Transient 32, "Extended Loss of Letdown" was added to the 73ST-9RC02 procedure in 1998. At that point, 200 cycles were assumed for Unit 3 only (25% of design), and 0 cycles for Units 1 and 2. The actual data recorded from 1995-2005 include 64 cycles of this transient for Unit 1, 0 cycles for Unit 2, and 2 cycles for Unit 3. The 73ST-9RC02 Worst-Case (1985-2005) column ignores the 200 assumed for Unit 3. The Worst-Case Composite Unit Accumulation for Transient 32, "Extended Loss of Letdown," is the 64 counted cycles from the Unit 1 surveillance data.

transient event cycles that have significant fatigue effects will be counted and tracked to ensure that the numbers of transient events assumed by the design basis calculations will not be exceeded. This "global" coverage will therefore suffice to demonstrate design basis compliance. See Table 4.3-3 for the list of tracked transients.

Corrective Action Limits and Corrective Actions

The PVNGS fatigue management program currently incorporates action limits that provide for evaluation ~~of fatigue usage~~ and cycle count tracking of critical thermal and pressure transients to verify that the ASME Code CUF limit of 1.0 and other ~~CUF~~ design limits will not be exceeded. The program requires this evaluation at least once per fuel cycle. Action limits are based on a fixed percentage of allowed cycles for components monitored by a maximum number of defined transients~~, while components whose CUF is monitored have specific CUF values for action limits~~. The current action limits are established to prevent exceeding the maximum number of allowed cycles or a CUF of 1.0, as applicable, and should provide at least one fuel cycle of warning.

The enhanced program specifies corrective actions to be implemented to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached.

Action Limit Margins

Corrective action limits must ensure that corrective actions are taken before the design limits are exceeded. Corrective action limits must therefore ensure that appropriate reevaluation or other corrective actions are initiated while sufficient margin remains to allow at least one occurrence of the worst case (highest fatigue usage per cycle) low probability transient that is included in design specifications, without exceeding the code limit CUF of 1.0. For NUREG/CR-6260 locations, CUF calculation will be done using the appropriate F_{en} environmental factor.

Cycle Count Action Limits and Corrective Actions

For Cycle-Based Fatigue monitoring (CBF), action limits have been established based on the design-specified number of cycles. Usage factors in locations monitored by this method are most affected by transient events which are of low probability, and cycle counting of these events is therefore sufficient to account for the fatigue accumulation in them.

Cycle Count Action Limit Margins: In order to assure sufficient margin to accommodate occurrence of a low probability transient, corrective actions must be taken before the remaining number of allowable occurrences for any specified transient, including the low-probability, higher-usage-factor events, becomes less than one. Other events counted by cycle-based monitoring contribute less per event to usage factor, but occur more frequently. To account for both cases, corrective actions are required when the cycle count for any of the significant contributors to usage factor is projected to reach the action limit defined in the program before the end of the next fuel cycle.

principal concerns in the evaluation of this problem. These evaluations were therefore examined to confirm that they include no TLAAs.

On March 18, 2006, PVNGS conducted a test to diagnose causes of high vibration in the Unit 1 Train A SDC suction line. The Train A SDC suction line is connected to the Loop 1 hot leg. This test operated both Loop 1 reactor coolant pumps but only one Loop 2 pump. This condition produced high Loop 1 flow, which caused ~~brief excursions of an~~ indications on the SDC Train A vibration monitor beyond both the administrative and analytical limits. A trip of a Loop 2 pump, under normal, four-pump operating conditions, could produce the same flow conditions and the same elevated vibration levels in the SDC line; and at these vibration levels, the time required for operator action to shut down the unit might result in unacceptable fatigue usage and eventual failure of the piping or isolation valve motor operator. Loop 1 was therefore restricted to single-pump operation, and the unit was maintained in a shutdown condition for evaluation and correction of the vibration condition.

The correction included moving the Unit 1 UV651 valve inboard, to increase the acoustic response above the line and valve resonance. Unit 1 has since operated at 100 percent power with acceptable vibration levels. APS has since moved the corresponding valves in Units 2 and 3 to prevent similar problems.

Absence of TLAAs

The evaluation of affected piping, supports, and piping components determined that maintaining vibration below the administrative limit would maintain alternating stresses below the endurance limit at the most limiting location. The evaluation of the UV651 valve actuator determined that maintaining vibration below the administrative limit would maintain accelerations below the revised vibration limits established for the actuator for indefinite, continuous operation. These evaluations are therefore not time-limited and are therefore not TLAAs. The evaluations of the piping and valve operator for effects of having exceeded the vibration administrative limit during the test determined that this single event did not produce unacceptable damage. Since these evaluations did not qualify either piping or valve for any similar excursions during the remaining life of the plant, these evaluations are not time-limited and are therefore not TLAAs.

4.3.2.14 High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

Summary Description

Break locations are determined in accordance with Branch Technical Position MEB 3-1. However, a leak-before-break analysis (LBB) eliminated the large breaks in the main reactor coolant loops. See Section 4.3.2.15 below.

A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of License Renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. Sections A1 and A2 describe the programs and their implementation activities.

Three elements common to all aging management programs discussed in Sections A1 and A2 are corrective actions, confirmation process, and administrative controls. These elements are included in the PVNGS Quality Assurance (QA) Program, which implements the requirements of 10 CFR 50, Appendix B. The PVNGS Quality Assurance Program is applicable to all safety-related and, after enhancement, will also be applicable to the nonsafety-related systems, structures and components that are subject to aging management review activities.

Procedures will be enhanced to include those nonsafety-related SSCs requiring aging management within the scope of the PVNGS Quality Assurance Program to address the elements of corrective actions, confirmation process, and administrative controls.

A1.1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program manages cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components within the scope of license renewal. The program includes periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. PVNGS inspections meet ASME Section XI requirements. The PVNGS third interval ISI Program is in accordance with 10 CFR 50.55a and ASME Section XI, 2001 Edition, through 2003 Addenda. PVNGS will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation.

A1.2 WATER CHEMISTRY

The Water Chemistry program includes maintenance of the chemical environment in the reactor coolant system and related auxiliary systems ~~containing treated borated water~~ and includes maintenance of the chemical environment in the steam generator secondary side and the secondary cycle systems to manage cracking, denting, hardening and loss of strength, loss of material, reduction of heat transfer, and wall thinning in primary and secondary water systems. The Water Chemistry program is based upon the guidelines of EPRI ~~1002884~~ 1014986, "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, and EPRI ~~1008224~~ 1016555, "*PWR Secondary Water Chemistry Guidelines*".

The effectiveness of the program is verified under the One-Time Inspection program (A1.16).

Prior to the period of extended operation, plant procedures will be enhanced to address sampling of effluents from new secondary system cation resins for purgeable and non-purgeable Organic Carbon.

A1.3 REACTOR HEAD CLOSURE STUDS

The Reactor Head Closure Studs program manages reactor vessel stud, nut and washer cracking and loss of material. The Reactor Head Closure Studs program includes periodic visual, surface, and volumetric examinations of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers and performs visual inspection of the reactor vessel flange closure during primary system leakage tests. The program implements ASME Section XI code, Subsection IWB, 2001 Edition through the 2003 addenda.

A1.4 BORIC ACID CORROSION

The Boric Acid Corrosion program manages loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective actions. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, "*Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*". Additionally, the program includes scheduled inspection of all plant borated water systems and examinations conducted during ISI pressure tests performed in accordance with ASME Section XI requirements. ~~The program addresses recent operating experience noted in NRC Regulatory Issue Summary 2003-13, "*NRC Review of Responses to Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity*" (which includes NRC Bulletin 2002-01, 2002-02, and NRC Order EA-03-009) and NRC Bulletin 2003-02, "*Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity*".~~ The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (A1.5) and the Nickel Alloy Aging Management Program (A1.34) as well as the Boric Acid Corrosion control program, implement reactor coolant pressure boundary inspections of reactor coolant pressure boundary components to identify degradation that would impact the reactor coolant pressure boundary.

A1.5 NICKEL-ALLOY PENETRATION NOZZLES WELDED TO THE UPPER REACTOR VESSEL CLOSURE HEADS OF PRESSURIZED WATER REACTORS

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking (PWSCC) and loss of material due to boric acid wastage in nickel-alloy pressure vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. The term "primary water stress corrosion cracking" applies to the nozzles and J-welds and "Wastage" applies to the reactor closure head. The aging management for the aging effect of wastage is addressed in Boric Acid Corrosion program (A1.4). This program was developed in response to NRC Order EA-03-009. ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6) has superseded the requirements of NRC Order EA-03-009.

Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and surface and volumetric examination (underside of head) techniques. Reactor Pressure Vessel Head bare metal visual examinations, surface examinations, and volumetric examinations are performed consistent with the ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6).

A1.6 FLOW-ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to FAC on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phases).

The objectives of the FAC program are achieved by (a) identifying system components susceptible to FAC, (b) an analysis using a predictive code such as CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance of follow-up inspections, (d) repairing or replacing components, as determined by the guidance provided by the program, and (e) continual evaluation and incorporation of the latest technologies, industry and plant in-house operating experience.

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

~~Prior to the period of extended operation, the program procedure will be enhanced to clarify the guidance for susceptible small-bore piping components and to verify the trace chromium content of the carbon steel pipe replacement.~~

A1.7 BOLTING INTEGRITY

The Bolting Integrity program manages cracking, loss of material, and loss of preload for pressure retaining bolting and ASME component support bolting. The program includes open-cycle cooling water system and components. The various aspects of the PVNGS program (control, monitoring, maintenance and inspection) are implemented in plant procedures.

Prior to the period of extended operation, the program will be enhanced to clarify guidance in the conduct of ~~heat exchanger and~~ piping inspections using NDE techniques and related acceptance criteria.

A1.10 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System program manages loss of material, cracking, and reduction in heat transfer for components in closed cycle cooling water systems. The program includes maintenance of system corrosion inhibitor concentrations and chemistry parameters following the guidance of EPRI TR-107396 to minimize aging, and periodic testing and inspections to evaluate system and component performance. Inspection methods include visual, ultrasonic testing and eddy current testing.

Prior to the period of extended operation, procedures will be enhanced to incorporate the guidance of EPRI TR-107396 with respect to water chemistry control for frequency of sampling and analysis, normal operating limits, action level concentrations, and times for implementing corrective actions upon attainment of action levels.

A1.11 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program manages loss of material for all cranes, trolley and hoist structural components, fuel handling equipment and applicable rails within the scope of license renewal. Program inspection activities verify the structural integrity of the components required to maintain their intended function. The inspection requirements are consistent with the guidance provided by NUREG-0612, "*Control of Heavy Loads at Nuclear Power Plants*" for load handling systems that handle heavy loads which can directly or indirectly cause a release of radioactive material, applicable industry standards (such as CMAA Spec 70) for other components within the scope of license renewal in this program, and applicable OSHA regulations (such as 29 CFR Volume XVII, Part 1910 and Section 1910.179).

Prior to the period of extended operation, procedures will be enhanced to inspect for loss of material due to corrosion or rail wear.

A1.12 FIRE PROTECTION

The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pumps, and the halon/CO_2 fire suppression systems, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors manage aging. Periodic testing of the diesel-driven fire pumps ensures that there is no loss of function due to aging of diesel fuel supply lines. Drop tests are performed on 10 percent of fire dampers on an 18 month basis to manage aging. Visual inspections manage aging of fire-rated doors every 18 months to verify the integrity of door surfaces and for clearances to detect aging of the fire doors. A visual inspection and function test of the halon and CO_2 fire suppression systems every 18 months manages aging. Ten percent of each type of penetration seal is visually inspected at least once every 18 months. Fire barrier walls, ceilings, and floors including coatings and wraps are visually inspected at least once every 18 months.

Prior to the period of extended operation, the following enhancements will be implemented:

- *Procedures will be enhanced to state trending requirements for the diesel-driven fire pump*~~and to include visual inspection of the fuel supply line to detect degradation~~.
- Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the CO_2 system discharge nozzles.
- Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors.

A1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests are performed considering applicable National Fire Protection Association (NFPA) codes and standards. The fire water system pressure is continuously monitored such that loss of system pressure is immediately detected and corrective actions are initiated. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler head to verify that each open head spray/sprinkler nozzle is unobstructed. Visual inspections of the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, are covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (A1.22). The Buried Piping and Tanks Inspection program (A1.18) is credited with the management of aging effects on the external surface of buried fire water system piping.

Prior to the period of extended operation, the following enhancements will be implemented:

- Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM).

- Procedures will be enhanced to be consistent with the current code of record or NFPA 25 2002 Edition.
- Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner.
- Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4.
- Procedures will be enhanced so that the PVNGS Quality Assurance programs will apply to Fire Protection SSCs that are within the scope of license renewal that are also part of the boundary of the WRF (Water Reclamation Facility).

A1.14 FUEL OIL CHEMISTRY

The Fuel Oil Chemistry program manages loss of material on the internal surface of components in the emergency diesel generator (EDG) fuel oil storage and transfer system, diesel fire pump fuel oil system, and station blackout generator (SBOG) system. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) visual inspection of internal surfaces during periodic draining and cleaning, (d) ultrasonic wall thickness measurements from external surfaces of fuel oil tanks if there are indications of reduced cross sectional thickness found during the visual inspection, (e) inspection of new fuel oil before it is introduced into the storage tanks, and (f) one-time inspections of a representative sample of components in systems that contain fuel oil by the One-Time Inspection program.

The effectiveness of the program is verified under the One-Time Inspection program (A1.16).

Prior to the period of extended operation:

Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks.

Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage ~~tanks~~ tank, and SBOG skid fuel tanks.

Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, ~~and~~ SBOG fuel oil storage ~~tanks~~ tank, and SBOG skid fuel tanks. The one-time UT or PEC examination on the tank bottoms will be performed before the period of extended operation.

A1.15 REACTOR VESSEL SURVEILLANCE

The Reactor Vessel Surveillance program manages loss of fracture toughness and is consistent with ASTM E 185. Actual reactor vessel plate coupons are used. Weld and heat-affected-zone coupons are made from sections of the same plate welded together with identical weld material heats and weld parameters. The surveillance coupons are tested by a qualified offsite vendor, to its procedures. The testing program and reporting conform to requirements of 10 CFR 50, Appendix H, "*Reactor Vessel Material Surveillance Program Requirements*".

Prior to the period of extended operation:

The schedule will be revised to withdraw the next capsule at the equivalent clad-base metal exposure of approximately 54 EFPY expected for the 60-year period of operation, and to withdraw remaining standby capsules at equivalent clad-base metal exposures not exceeding the 72 EFPY expected for a possible 80-year second period of extended operation. This withdrawal schedule is in accordance with NUREG-1801, Section XI.M31, item 6, and with the ASTM E 185-82 criterion which states that capsules may be removed when the capsule neutron fluence is between one and two times the limiting fluence calculated for the vessel at the end of expected life. This schedule change must be approved by the NRC, as required by 10 CFR 50 Appendix H.

If left in the reactor beyond the presently-scheduled withdrawal, the next scheduled surveillance capsule in each unit will reach a clad-base metal 54 EFPY equivalent at about 40 actual operating EFPY (40, 39, and 42 actual EFPY in Units 1, 2, and 3, respectively).

Procedures will be enhanced to identify the withdrawal of the remaining standby capsules at 72 EFPY, at about 50 to 54 actual operating EFPY, near the end of the extended licensed operating period. The need to monitor vessel fluence following removal of the remaining standby capsules, and ex-vessel or in-vessel methods, will be addressed prior to removing the remaining capsules.

A1.16 ONE-TIME INSPECTION

The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (A1.2), Fuel Oil Chemistry program (A1.14), and Lubricating Oil Analysis program (A1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. The One-Time Inspection program will include the specific.

attributes for the components crediting this program for aging management in the license renewal application.

Plant system piping and components will be subject to one-time inspection on a sampling basis using qualified inspection personnel following established ASME, "*Boiler and Pressure Vessel Code*", Section V, "Nondestructive Examination", (NDE) techniques appropriate to each inspection. Inspection sample sizes will be determined using a methodology that is based on 90% confidence that 90% of the population of components will not experience aging effects in the period of extended operation. The One-Time Inspection program specifies corrective actions and increased sampling of piping/components if aging effects are found during material/environment combination inspections. The one-time inspections will be performed no earlier than 10 years prior to the period of extended operation. All one-time inspections will be completed prior to the period of extended operation. Completion of the One-Time Inspection program in this time period will assure that potential aging effects will be manifested based on at least 30 years of PVNGS operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Major elements of the PVNGS One-Time Inspection program include:

a) Identifying piping and component populations subject to one-time inspection based on common materials and environments,

b) Determining the sample size of components to inspect using established statistical methods based on the population size of the material-environment groups,

c) Selecting piping and components within the material-environment groups for inspection based on criteria provided in the One-Time Inspection procedure,

d) Conducting one-time inspections of the selected components within the sample using ASME Code Section V NDE techniques and acceptance criteria consistent with the design codes/standards or ASME Section XI as applicable to the component.

A1.17 SELECTIVE LEACHING OF MATERIALS

The Selective Leaching of Materials program manages the loss of material due to selective leaching for brass (copper alloy >15% zinc), aluminum-bronze (copper alloy >8% aluminum), and gray cast iron components exposed to closed-cycle cooling water demineralized water, secondary water, ~~and raw water~~ raw water and wetted gas within the scope of license renewal. The Selective Leaching of Materials program is in addition to the Open-Cycle Cooling Water program (A1.9) and the Closed-Cycle Cooling Water program (A1.10) in these cases.

The program includes a one-time inspection (visual and/or mechanical methods) of a selected sample of components internal surfaces to determine whether loss of material due to selective leaching is occurring. If indications of selective leaching are confirmed, follow up examinations or evaluations are performed.

~~The Selective Leaching of Materials program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.~~

A1.18 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection program manages loss of material of buried components in the chemical and volume control, condensate storage and transfer, diesel fuel storage and transfer, domestic water, fire protection, ~~WRF~~ SBOG fuel system, service gas and essential spray ponds systems. Visual inspections monitor the condition of protective coatings and wrappings found on carbon steel, gray cast iron or ductile iron components and assess the condition of stainless steel components with no protective coatings or wraps. The program includes opportunistic inspection of buried piping and tanks as they are excavated or on a planned basis if opportunistic inspections have not occurred.

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended of operation. Within the ten year period prior to entering the period of extended operation, an opportunistic or planned inspection will be performed. Upon entering the period of extended operation a planned inspection within ten years will be required unless an opportunistic inspection has occurred within this ten year period. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.19 ONE-TIME INSPECTION OF ASME CODE CLASS 1 SMALL-BORE PIPING

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of stainless steel ASME Code Class 1 piping less than or equal to 4 inches. ~~This program is a part of the Risk-Informed Inservice Inspection (RI-ISI) program.~~

For ASME Code Class 1 small-bore piping, ~~the RI-ISI program requires volumetric examinations on selected weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657. Volumetric examinations are conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. The fourth interval of the ISI program for each unit at PVNGS will provide the results for the one time inspection of ASME Code Class 1 small-bore piping.~~ volumetric examinations on selected butt weld locations will be performed to detect cracking. Butt weld volumetric examinations will be conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. Weld locations subject to volumetric examination will be selected based on the guidelines provided in EPRI TR-112657. Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. If a qualified volumetric examination procedure for socket welds endorsed by the industry and the NRC is available and incorporated into the ASME Section XI Code at the time of PVNGS small-bore socket weld inspections then volumetric examinations will be conducted on small-bore socket welds as part of the PVNGS program. ~~The one-time inspection of ASME Code Class 1 small-bore piping will be completed prior to the period of extended operation.~~

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.25 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

The scope of this program includes the cables and connections used in sensitive instrumentation circuits with sensitive, high voltage low-level signals within the Ex-core Neutron Monitoring System including the source range, intermediate range, and power range monitors. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program manages embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance.

This program provides reasonable assurance that the intended function of cables and connections used in instrumentation circuits with sensitive, low-level signals 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 are maintained consistent with the current licensing basis through the period of extended operation. In most areas, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment for those areas.

Calibration surveillance tests are used to manage the aging of the cable insulation and connections so that instrumentation circuits perform their intended functions. When an instrumentation channel is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable and connections. A review of calibration results will be completed prior to the period of extended operation and every 10 years thereafter.

Prior to the period of extended operation, procedures will be enhanced to identify license renewal scope and require an~~ engineering ~~evaluation of the calibration results~~ and to require that an action request be written when the loop cannot be calibrated to meet acceptance criteria~~.

A1.26 INACCESSIBLE MEDIUM VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program manages localized damage and breakdown of insulation leading to electrical failure in inaccessible medium voltage cables exposed to adverse localized environments caused by significant moisture simultaneously with significant voltage to ensure that inaccessible medium voltage cables not subject to the environmental qualification (EQ) requirements of

A1.34 NICKEL ALLOY AGING MANAGEMENT PROGRAM

The Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all plant locations that contain Alloy 600, with the exception of steam generator tubing (aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (A1.8)) and reactor vessel internals (aging management of reactor vessel internals is addressed in Reactor Coolant System Supplement (A1.21)). Aging management requirements for Alloy 600 penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (A1.5) are included in this program. This program includes Alloy 600 reactor coolant pressure boundary locations in the reactor coolant system (RCS) and ESF systems.

The Alloy 600 aging management program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at PVNGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB, ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4), and EPRI Report ~~1010087~~ <u>1015009</u> (MRP-139) issued under NEI 03-08 protocol. Mitigation techniques are implemented when appropriate to preemptively remove conditions that contribute to primary water stress corrosion cracking. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw. Mitigation and repair/replace activities are consistent with those detailed in EPRI Report ~~1010087~~ <u>1015009</u> (MRP-139). ~~The inspection plan of Alloy 690 replacement is also included in this program.~~

A1.35 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the effects of loosening of bolted external connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. As part of the PVNGS predictive maintenance program, infrared thermography testing is being performed on non-EQ electrical cable connections, associated with active and passive components within the scope of license renewal. A representative sample will be tested at least once prior to the period of extended operation using infrared thermography to confirm that there are no aging effects requiring management during the period of extended operation. The selected sample is based upon application (medium and low voltage), circuit loading, and environment.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.36 METAL ENCLOSED BUS

The Metal Enclosed Bus (MEB) program manages the effects of loose connections, embrittlement, cracking, melting, swelling, or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports to ensure that metal-enclosed buses within the scope of license renewal. Internal portions of MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, hardening or discoloration, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets. Samples of the accessible bolted connections on the internal bus work are checked for loose connections by measuring connection resistance.

The Metal Enclosed Bus program is a new program and will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.37 FUSE HOLDERS

The Fuse Holders program manages thermal fatigue, mechanical fatigue, vibration, chemical contamination, and corrosion of the metallic portions of fuse holders to ensure that fuse holders within the scope of license renewal are capable of performing their intended function.

The Fuse Holder program is a new program that will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
7	Existing Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program is credited for license renewal, AND Prior to December 31, 2008, the PVNGS Alloy 600 Management Program Plan will be revised to incorporate the applicable examination requirements of ASME Code Case N-729-1 (Reactor Vessel Head Inspections), subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6). (RCTSAI 3246894) **(Completed)**	A1.5 B2.1.5 Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Ongoing
8	Existing Flow-Accelerated Corrosion program is credited for license renewal, AND Prior to the period of extended operation, the program ~~procedure~~ will be enhanced to clarify the guidance for susceptible small-bore piping components **(Completed)** ~~and to verify the trace chromium content of the carbon steel pipe replacement~~. (RCTSAI 3246895)	A1.6 B2.1.6 Flow-Accelerated Corrosion	~~Prior to the period of extended operation[1].~~ Ongoing
9	Existing Bolting Integrity program is credited for license renewal. (RCTSAI 3246896)	A1.7 B2.1.7 Bolting Integrity	Ongoing
10	Existing Steam Generator Tube Integrity program is credited for license renewal. (RCTSAI 3246897)	A1.8 B2.1.8 Steam Generator Tube Integrity	Ongoing
11	Existing Open-Cycle Cooling Water System program is credited for license renewal, AND Prior to the period of extended operation, the program will be enhanced to: • clarify guidance in the conduct of heat exchanger inspections using NDE techniques and related acceptance criteria **(Completed),** and • clarify guidance in the conduct of piping inspections using NDE techniques and related acceptance criteria. (RCTSAI 3246898)	A1.9 B2.1.9 Open-Cycle Cooling Water System	Prior to the period of extended operation[1]

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
12	Existing Closed-Cycle Cooling Water System program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to incorporate the guidance of EPRI TR-107396 with respect to water chemistry control for frequency of sampling and analysis, normal operating limits, action level concentrations, and times for implementing corrective actions upon attainment of action levels. (RCTSAI 3246899)	A1.10 B2.1.10 Closed-Cycle Cooling Water System	Prior to the period of extended operation[1].
13	Existing Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to inspect for loss of material due to corrosion or rail wear. (RCTSAI 3246900)	A1.11 B2.1.11 Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems	Prior to the period of extended operation[1].
14	Existing Fire Protection program is credited for license renewal, AND Prior to the period of extended operation, the following enhancements will be implemented: • Procedures will be enhanced to state trending requirements for the diesel-driven fire pump. ~~and~~ • Procedures will be enhanced to include visual inspection of the fuel supply line to detect degradation. **(Completed)** • Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the halon discharge pipe header **(Completed)** and the CO_2 system discharge nozzles. • Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors. (RCTSAI 3246901)	A1.12 B2.1.12 Fire Protection	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
16	Existing Fuel Oil Chemistry program is credited for license renewal, AND Prior to the period of extended operation: • Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks. • Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage tank~~s~~, and SBOG skid fuel tanks. • Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, ~~and~~ SBOG fuel oil storage ~~tanks~~ tank, and SBOG skid fuel tanks. The onetime UT or PEC examination on the tank bottoms will be performed before the period of extended operation. (RCTSAI 3246903)	A1.14 B2.1.14 Fuel Oil Chemistry	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
18	The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (A1.2), Fuel Oil Chemistry program (A1.14), and Lubricating Oil Analysis program (A1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. (RCTSAIs 3246906 [U1]; 3247258 [U2]; 3247259 [U3])	A1.16 B2.1.16 One-Time Inspection	Prior to the period of extended operation[1].
19	The Selective Leaching of Materials program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246908 [U1]; 3247260 [U2]; 3247261 [U3]) **(Completed)**	A1.17 B2.1.17 Selective Leaching Of Materials	~~Prior to the period of extended operation[1].~~ Ongoing
20	The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended of operation. Within the ten year period prior to entering the period of extended operation, an opportunistic or planned inspection will be performed. Upon entering the period of extended operation a planned inspection within ten years will be required unless an opportunistic inspection has occurred within this ten year period. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246909 [U1]; 3247263 [U2]; 3247264 [U3])	A1.18 B2.1.18 Buried Piping And Tanks Inspection	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
21	The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program ~~manages cracking of stainless steel ASME Code Class 1 piping less than or equal to 4 inches~~ is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. ~~This program is a part of the Risk-Informed Inservice Inspection (RI-ISI) program.~~ ~~For ASME Code Class 1 small-bore piping, the RI-ISI program requires volumetric examinations on selected weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657. Volumetric examinations are conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. The fourth interval of the ISI program for each unit at PVNGS will provide the results for the one-time inspection of ASME Code Class 1 small-bore piping.~~ (RCTSAIs 3246910 [U1]; 3247265 [U2]; 3247266 [U3])	A1.19 B2.1.19 One-Time Inspection of ASME Code Class 1 Small-Bore Piping	Prior to the period of extended operation[1].
22	The External Surfaces Monitoring Program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246911 [U1]; 3247272 [U2]; 3247273 [U3])	A1.20 B2.1.20 External Surfaces Monitoring Program	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
26	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAI 3246917)	A1.24 B2.1.24 Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Prior to the period of extended operation[1].
27	Existing Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits program is credited for license renewal , AND Prior to the period of extended operation: • Procedures will be enhanced to identify license renewal scope and require an ~~engineering~~ evaluation of the calibration results. ~~and~~ • Procedures will be enhanced to require that an action request be written when the loop cannot be calibrated to meet acceptance criteria. **(Completed)** (RCTSAI 3246919)	A1.25 B2.1.25 Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits	Prior to the period of extended operation[1].
28	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAI 3246920)	A1.26 B2.1.26 Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	Prior to the period of extended operation[1].
29	Existing ASME Section XI, Subsection IWE program is credited for license renewal. (RCTSAI 3246921)	A1.27 B2.1.27 ASME Section XI, Subsection IWE	Ongoing

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
50	The Fuse Holder program is a new program that will be implemented prior to the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program (RCTSAI 3409443)	A1.37 B2.1.37 Fuse Holder	Prior to the period of extended operation and once every 10 years thereafter.
51	The original Unit 1 and Unit 3 reactor pressure vessel (RPV) heads are planned to be replaced during the refueling outages in 2010. All components penetrating the new heads and welds including the head vent will be replaced with Alloy 690. (RCTSAI 3410460)	B2.1.34 Nickel Alloy Aging Management Program	12/31/10

(1) "Prior to period of extended operation," "prior to operation beyond 32 EFPY," and "prior to the end of the current licensed operating period," is prior to the following PVNGS Operating License expiration dates: Unit 1: June 1, 2025; Unit 2: April 24, 2026; Unit 3: November 25, 2027.

- External Surfaces Monitoring Program (Section B2.1.20)
- Reactor Coolant System Supplement (Section B2.1.21)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B2.1.22)
- Lubricating Oil Analysis (Section B2.1.23)
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B2.1.24)
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B2.1.25)
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B2.1.26)
- ASME Section XI, Subsection IWE (Section B2.1.27)
- ASME Section XI, Subsection IWL (Section B2.1.28)
- ASME Section XI, Subsection IWF (Section B2.1.29)
- 10 CFR 50, Appendix J (Section B2.1.30)
- Masonry Wall Program (Section B2.1.31)
- Structures Monitoring Program (Section B2.1.32)
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B2.1.33)
- Nickel Alloy Aging Management Program (Section B2.1.34)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B2.1.35)
- Metal Enclosed Bus (Section B2.1.36)
- <u>Fuse Holders (Section B2.1.37)</u>

B1.6 TIME-LIMITED AGING ANALYSIS PROGRAMS

The following time-limited aging analysis aging management programs are described in this section. These programs are discussed in NUREG -1801. All programs discussed in this section are existing plant programs.

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	PLANT PROGRAM	EXISTING OR NEW	APPENDIX B REFERENCE
XI.M27	Fire Water System	Fire Water System	Existing	B2.1.13
XI.M28	Buried Piping and Tanks Surveillance	Not Credited	N/A	N/A
XI.M29	Aboveground Steel Tanks	Not Credited	N/A	N/A
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry	Existing	B2.1.14
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance	Existing	B2.1.15
XI.M32	One-Time Inspection	One-Time Inspection	New	B2.1.16
XI.M33	Selective Leaching of Materials	Selective Leaching of Materials	~~New~~ <u>Existing</u>	B2.1.17
XI.M34	Buried Piping and Tanks Inspection	Buried Piping and Tanks Inspection	New	B2.1.18
XI.M35	One-Time Inspection of ASME Code Class 1 Small-Bore Piping	One-Time Inspection of ASME Code Class 1 Small-Bore Piping	<u>New</u> ~~Existing~~	B2.1.19
XI.M.36	External Surfaces Monitoring Program	External Surfaces Monitoring Program	New	B2.1.20
XI.M37	Flux Thimble Tube Inspection	Not Credited	N/A	N/A
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New	B2.1.22
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis	Existing	B2.1.23
XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New	B2.1.24

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	PLANT PROGRAM	EXISTING OR NEW	APPENDIX B REFERENCE
XI.E2	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Existing	B2.1.25
XI.E3	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New	B2.1.26
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus	New	B2.1.36
XI.E5	Fuse Holders	~~Not Credited~~<u>Fuse Holders</u>	~~N/A~~<u>New</u>	~~N/A~~<u>B2.1.37</u>
XI.E6	Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New	B2.1.35
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE	Existing	B2.1.27
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL	Existing	B2.1.28
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF	Existing	B2.1.29
XI.S4	10 CFR 50, Appendix J	10 CFR 50, Appendix J	Existing	B2.1.30
XI.S5	Masonry Wall Program	Masonry Wall Program	Existing	B2.1.31
XI.S6	Structures Monitoring Program	Structures Monitoring Program	Existing	B2.1.32
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing	B2.1.33

B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program manages cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components within the scope of license renewal. The program includes periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. These components are identified in ASME Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively. The ASME Section XI ISI Program has proven within the industry to maintain component structural integrity and ensure that aging effects are discovered and repaired before the loss of component intended function. The PVNGS ISI Program is consistent with ASME Section XI 2001 edition with addenda 2002 and 2003. PVNGS will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation.

In conformance with 10 CFR 50.55a(g)(4)(ii), the PVNGS ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition of the Code specified twelve months before the start of the inspection interval.

PVNGS Units 1, 2, and 3 are in the third ISI interval which began July 18, 2008, March 18, 2007, and January 11, 2008, respectively. The program is being conducted in accordance with ASME Section XI, 2001 edition with addenda 2002 and 2003 which is consistent with provisions in 10 CFR 50.55a to use the ASME Code in effect 12 months prior to the start of the inspection interval. PVNGS is following Inspection Program B as allowed by the ASME Code. Requirements are included for scheduling of examinations and tests for Class 1, 2, and 3 components. The program requires periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components. The PVNGS ASME Section XI ISI program provides measures for monitoring to detect aging effects prior to loss of intended function and provides measures for repair and replacement of components with aging effects.

Inservice inspection of reactor vessel flange stud holes, closure studs, nuts, and washers is evaluated in the Reactor Head Closure Studs program (B2.1.3).

Inservice inspection of Class 1, 2, and 3 component supports is evaluated in the ASME Section XI, Subsection IWF program (B2.1.29).

NUREG-1801 Consistency

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing program that is consistent with NUREG-1801, Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD".

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Review of PVNGS plant-specific operating experience for the PVNGS ISI Program has not revealed any program adequacy issues or implementation issues with the PVNGS ASME Section XI ISI Program. Industry operating experience is evaluated by PVNGS for relevancy to PVNGS and appropriate actions are taken and documented. Based on these results the PVNGS ISI Program is effective in monitoring ASME Class 1, 2 and 3 components and detecting aging effects prior to loss of intended function.

Review of ~~the Second 10-year ISI Interval~~ Summary Reports for Units 1, 2 and 3 for the last 10 years indicates there were ~~no~~ three code repairs or code replacements required for continued service of ASME IWB, IWC, and IWD Code components during ~~the 10 year period.~~ these 10 years. In the first case, a 2-inch vent nozzle attachment weld was added to the OD of the Safety Injection Tank because the ID weld could have had a through-wall leak. In the second case, a 6-inch spray pond pipe spool which is part of the diesel intercooler was replaced due to corrosion. These 2 cases occurred on Unit 1 during Refuel 13. In the third case, a check valve in the Chemical and Volume Control System was replaced because of a failure of the weld between the seat and the body. This occurred in Unit 2 in Refuel 14. The ~~Second 10-year ISI Interval~~ Summary Reports did not indicate any implementation issues with the PVNGS ASME Section XI Program for ASME IWB, IWC, and IWD Code components.

The ISI Program at PVNGS is updated to account for industry operating experience. ASME Section XI is revised every three years and addenda issued in the interim, which allows the code to be updated to reflect operating experience. The requirement to update the ISI Program to reference more recent editions of ASME Section XI at the end of each inspection interval ensures the ISI Program reflects enhancements due to operating experience that have been incorporated into ASME Section XI.

Conclusion

The continued implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.2 Water Chemistry

Program Description

The Water Chemistry program manages cracking, denting, hardening and loss of strength, loss of material, reduction of heat transfer, and wall thinning in primary and secondary water systems. The scope of the Primary Water Chemistry Control Program includes maintenance of the chemical environment in the reactor coolant system and related auxiliary systems~~ containing treated borated water~~. The scope of the Secondary Water Chemistry Control Program includes maintenance of the chemical environment in the Steam Generator secondary side and the secondary cycle systems to limit aging effects associated with corrosion mechanisms and stress corrosion cracking. The Primary Water Chemistry Control Program is consistent with the guidelines of EPRI ~~1002884~~ 105714 "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, both Revision 6~~5~~ (issued as TR-1014986), and specific actions for exceeding the Technical Requirements Manual limits of fluorides, chlorides and dissolved oxygen. The Secondary Water Chemistry Control Program is consistent with EPRI ~~1008224~~ 102134, "*PWR Secondary Water Chemistry Guidelines*", Revision 7~~6~~ (issued as TR-1016555).

The water chemistry control strategies are set forth in station strategic plans and these strategies are implemented in station procedures. The programmatic control of the chemical environment ensures that the aging effects due to contaminants are limited. The methods used to manage both the primary and secondary chemical environments rely on the principles of: (1) limiting the concentration of chemical species known to cause corrosion, and (2) addition of chemical species known to inhibit degradation by their influence on pH and dissolved oxygen levels. Water chemistry control is effective in areas of intermediate and high flow where thorough mixing takes place and the monitoring samples are representative of actual conditions. For low flow areas and stagnant portions of the systems sampling may not be as effective in determining local environmental conditions, and a one-time inspection (B2.1.16) of a representative group of components will provide verification of the effectiveness of the Water Chemistry program in these low flow areas.

NUREG-1801 states that the Water Chemistry program is based on guidelines in EPRI report TR-105714, Revision 3, for primary water chemistry, and TR-102134, Revision 3, for secondary water chemistry. PVNGS has adopted EPRI ~~1002884~~1014986, Volumes 1 and 2, Revision 6~~5~~, for primary water chemistry and EPRI ~~1008224~~1016555, Revision 7~~6~~, for secondary water chemistry. The Revision 6~~5~~ changes to EPRI 1014986~~1002884~~ consider the most recent operating experience and laboratory data. These guideline revisions reflect increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the NEI steam generator initiative, NEI 97-06, which requires utilities to be consistent with the EPRI Guidelines, and NEI 03-08. EPRI 1002884, Volumes 1 and 2, Revision 5, distinguished between prescriptive requirements and non-prescriptive guidance. Revision 4 of TR-102134 provided an increased depth of detail regarding the corrosion mechanisms affecting steam generators and the balance of plant, and it provided additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 of TR-102134 provided additional details regarding plant-specific optimization and clarified which portions of the EPRI Guidelines are mandatory under NEI 97-06. EPRI 1008224, Revision 6, made minor changes including revised action level 3 requirements, establishing hydrazine action levels and making several control parameter limits more restrictive. Future revisions of the EPRI Primary and Secondary Water Chemistry Guidelines will be adopted as required, commensurate with industry standards.

The One-Time Inspection program (Section B2.1.16) will be used to verify the effectiveness of the Water Chemistry program.

NUREG-1801 Consistency

The Water Chemistry program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI.M2, "Water Chemistry".

Exceptions to NUREG-1801

None

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Scope of Program - Element 1 and Preventative Actions – Element 2

Plant procedures will be enhanced to address sampling of effluents from new secondary system cation resins for purgeable and non-purgeable Organic Carbon.

Operating Experience

The Water Chemistry program is consistent with the EPRI Primary and Secondary Water Chemistry Control Guidelines, Revisions 5 and 6, respectively and therefore benefit from the industry operating experience available when the EPRI guidelines were issued. The Water Chemistry program will continue to evolve in response to ongoing plant operating experience and industry operating experience as conveyed in future revisions to EPRI Guidelines.

PVNGS Primary Chemistry Control:

The station optimization report for primary chemistry control incorporates PVNGS primary chemistry operating history regarding such topics as; RCS pH control program, minimization of Axial Offset Anomaly (AOA), high RCS fluoride, RCS zinc injection, RCS peroxidation, and corrosion product transport control.

High RCS fluoride has been experienced by all three PVNGS units following six refueling outages (U3R6; U2R7; U1R7; U3R7; U2R8 and U1R8). The maximum concentration observed during these outages was 260 ppb during the U3R6 startup. The cause of the fluoride ingress was the degradation of eddy current probe conduit. The conduit liner is composed of Teflon, which deposits small scrapings in the steam generator tubes as a result of eddy current testing. During plant startup, the Teflon is transported throughout the RCS and decomposes as a function of reactor power. A new improved eddy current conduit has been used since U3R8 and has corrected the condition. The highest startup fluoride since using the improved conduit has been 22 ppb through U3R10. There have been no discernable releases of fluoride to the RCS since December 2003.

On December 5, 2007, debris was found in Palo Verde Unit 3 reactor vessel on the core support plate following Steam Generator replacement. Two days later, an empty desiccant bag was found floating in the refueling cavity. Analysis determined the debris was identical to desiccant material used during transportation of new fuel handling equipment. Per analysis of the desiccant material, the primary constituents of concern were calcium, magnesium, and aluminum. Approximately 1.75 pounds of desiccant entered the reactor coolant system. Vacuum removal of the foreign material from the Reactor Vessel Lower Support structure and other identified areas in the Refueling Pool was completed on 12/12/07. Particulate cleanup of the RCS followed using both purification and ion exchange. Enhanced RCS monitoring for calcium, magnesium, aluminum and suspended solids was conducted during plant heatup and power ascension. Calcium and magnesium concentrations did not challenge fuel vendor limits. Aluminum reached a peak value of 155 ppb during Mode 3 operation and was reduced to a level of 6 ppb prior to critical reactor operation.

PVNGS Secondary Chemistry Control:

The station optimization report for secondary chemistry control incorporates PVNGS secondary chemistry operating history regarding iron transport reduction, condenser integrity and dissolved oxygen control. There have been no major primary chemistry excursions during PVNGS' operating history and no major secondary chemistry excursions since the replacement of the steam generators.

In November 2004 Unit 3 was completing 3R11 in which condenser tube plugs were replaced. During the plug replacement there were two tube plugs, one each in the 2A and 2C hotwells that were not installed in the correct locations. Because of a modification that had occurred several years ago, a 1/8-inch hole was drilled in all plugged tubes and a leak path therefore existed in the two tubes with the plugs missing, which allowed circ water to enter the hotwells. Maximum condensate impurities were 567 ppm chloride, 335 ppm sodium and 385 ppm sulfate. This condition lasted for several days before the tubes were located and plugged.

Prior to startup a decision was made to drain and refill the system at least once to help expedite the cleanup. The impurities following the first drain and refill went from 509 ppm chloride to 86 ppm chloride, or 83% cleanup. The above was repeated and the second drain and refill lowered chloride to approximately 6 ppm, or a 93% cleanup. Condensate polishing and steam generator blowdown were used after startup to further reduce impurities. Corrective actions included the development of official tubesheet maps to be used and updated as appropriate, following the addition of new plugs and additional administrative controls for personnel installing and verifying tube plugs.

On October 6, 2007 sodium ingress into the Unit 2 Condenser Hotwell caused by a failed tube plug in the "D" Condenser Air Removal (AR) System seal water cooler caused the Steam Generators to enter Action Level 3. The unit was operating on condensate polisher bypass and the polishers could not be put into service before Steam Generator sodium levels increased above 1 ppm and the reactor was tripped. The root cause of the event was inadequate questioning attitude and technical rigor by the Engineer, Technical Reviewer, and the Approver of the DFWO and EDC which installed the AR tube plug in January 2001. The consequences of installing material with a potential for corrosion was not adequately assessed.

On September 27, 2008 Unit 3 was operating with full condensate flow through 5 demineralizer service vessels when condensate demineralizer resin was allowed to enter the secondary system and the steam generator. Action Level 3 for cation conductivity and sulfate concentration was exceeded and the plant shutdown, as required. The direct cause of the SG sulfate concentration increase was resin intrusion from the condensate demineralizer system caused by resin leakage past the seat of a regeneration valve.

Conclusion

The continued implementation of the Water Chemistry program, supplemented by the One-Time Inspection program (B2.1.16), provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.4 Boric Acid Corrosion

Program Description

The Boric Acid Corrosion Control program manages loss of material due to borated water leakage. The program monitors mechanical, electrical and structural components within the scope of license renewal that are susceptible to boric acid corrosion from systems that contain reactor coolant or borated water. The principal industry guidance document used is WCAP-15988-NP, "*Generic Guidance for an effective Boric Acid Inspection Program for Pressurized Water Reactors*". The program relies in part on implementation of recommendations contained in NRC Generic Letter 88-05, "*Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*". Additionally, the program includes examinations conducted during ISI pressure tests performed in accordance with ASME Section XI requirements. ~~The program addresses recent operating experience noted in NRC Regulatory Issue Summary 2003-13, "*NRC Review of Responses to Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity*", (which includes NRC Bulletin 2002-01, 2002-02, and NRC Order EA-03-009) and NRC Bulletin 2003-02, "*Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity*".~~ The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (B2.1.5) and the Nickel Alloy Aging Management Program (B2.1.34) as well as the Boric Acid Corrosion control program, implement reactor coolant pressure boundary inspections of reactor coolant pressure boundary components to identify degradation that would impact the reactor coolant pressure boundary.

The Boric Acid Corrosion program includes provisions to identify leakage, inspect and examine for evidence of leakage, evaluate leakage, and initiate corrective actions. The program maintains a tracking and trending program for boric acid leakage from plant components and establishment of a component-based visual history of boric acid leakage/seepage.

NUREG-1801 Consistency

The Boric Acid Corrosion program is an existing program that is consistent with NUREG-1801, Section XI.M10, "Boric Acid Corrosion".

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Industry operating experience indicates that boric acid leakage can cause significant corrosion damage to susceptible plant components. In response to recent NRC generic communications, the reactor coolant system pressure boundary integrity walkdowns have been revised to perform periodic visual inspection of the reactor coolant system components, the reactor pressure vessel upper head and bottom head, and document any indication of leakage.

A review of the corrective action program and the work order process both show that boric acid leakage is being identified, evaluated and the resulting component damage is being repaired for the three Units. A review of plant operating experience indicates instances of boric acid concerns identified either on the components from which it leaked and/or on the surrounding equipment. Several occurrences were documented where increased reactor coolant system leakage prompted a containment entry where boric acid leakage was identified from various components within the containment. Both active leakage and crystal buildup have been identified and the effects mitigated without resulting in a loss of intended functions.

Conclusion

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

B2.1.5 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

Program Description

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking (PWSCC) and loss of material due to boric acid wastage in nickel-alloy pressure vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. The program for Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (Upper Head Nickel Alloy AMP) was developed by PVNGS to respond to NRC Order EA-03-009. ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), has superseded the requirements of NRC Order EA-03-009. The aging management for the aging effect of loss of material of the upper vessel head due to wastage is also included in the Boric Acid Corrosion program (B2.1.4).

Detection of cracking (including cracking induced by PWSCC) is accomplished through implementation of a combination of bare metal visual examination (external surface of the RPV closure head) surface and volumetric examinations (underside of RPV head) techniques. Underside of RPV head examinations include volumetric examination of the control element drive mechanism penetration tube walls, surface examination of the inner diameter of the penetrations, and surface examination of the J-groove weld. Examinations are consistent with ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6). Visual examinations are performed by VT-2 certified personnel.

The Alloy 600 Management Program Plan maintains the integrity and operability for all nickel alloy components at PVNGS.

NUREG-1801 Consistency

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program is an existing program that is consistent with NUREG-1801, Section XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors".

Exceptions to NUREG-1801

None

Enhancements

None.

Operating Experience

Inspections completed to date have indicated no evidence of PWSCC in the vessel head penetration nozzles with the exception of vent line indications on Unit 2 which were repaired by machining and subsequently weld overlayed during refueling outage U2R13. ~~Reactor vessel head replacements for all three PVNGS Units are scheduled from year 2009 to year 2010.~~ The original Unit 1 and Unit 3 reactor pressure vessel (RPV) heads are planned to be replaced during the refueling outages in 2010. The Unit 2 RPV head was replaced during the 2R15 outage in Fall 2009.

The following is a summary of information that has been provided to the NRC concerning inspections per the requirements of NRC Order EA-03-009:

PVNGS UNIT 1 - REFUELING 12 (U1R12) ending in December, 2005

A visual examination of the bare-metal surface of the reactor head found no evidence of boron or corrosion. No cleaning of the RPV head was necessary during U1R12. Additionally, a boric acid walkdown was performed for the U1R12 refueling outage. Potential boric acid leak sites from pressure retaining components above the RPV head were examined. No leaks or evidence of leakage was found.

Ninety seven control element drive mechanism penetrations had nondestructive exams performed. Eighty four were acceptable with no detectable defects and thirteen had additional examinations performed as a result of the initial examinations. The additional examinations performed on the thirteen penetrations were acceptable with no detectable defects found.

In preparation for modifying the head vent nozzle in Unit 1 to remove the flow-restricting orifice, the vent penetration J-weld and orifice J-weld were examined with manual eddy current testing techniques. Upon removal of the orifice, a surface examination (eddy current) of the J-groove weld and inside nozzle surface was performed as required. The head vent nozzles at PVNGS do not protrude below the surface of the RPV head and, as a result, there is no material below the J-groove weld to be examined. Although two areas of reduced wall dimension were noted, the results of the examinations were acceptable with no detectable defects. The head vent orifice was relocated to a downstream flange.

PVNGS UNIT 2 - REFUELING 15 (U2R15)~~13 (U2R13) ending in November, 2006~~

~~The visual examination of the bare-metal surface of the reactor head found no evidence of boron or corrosion. Additionally, a Boric Acid Walkdown was performed for the U2R13~~

~~refueling outage. Potential boric acid leak sites from pressure retaining components above the RPV head were examined. No indications of previously unreported leakage were identified. The two sites with boric acid deposit at CEDM vents were cleaned and reworked during U2R13. No cleaning of the RPV head was necessary during U2R13.~~

~~Non-visual NDE was performed for the reactor head vent nozzle. The two locations of axial indications, which were previously confirmed on the reactor head vent nozzle ID surface and repaired by grinding the indications to an acceptable condition during U2R12 refueling outage, were re-examined during U2R13. Unacceptable indications at or near the same area as those repaired in U2R12 were found. The vent line was repaired with weld overlay using Inconel 52 weld material. These indications were characterized as axial, were not through-wall and there was no evidence of RCS pressure boundary leakage.~~

~~The minimum required inspection coverage was obtained for all control element drive mechanism nozzles using ultrasonic and eddy current examination. No flaws were identified.~~ During U2R15 outage in 2009, the reactor pressure vessel head for Unit 2 was replaced. All components penetrating the new heads and welds including the head vent are Alloy 690.

Pre Service Examinations were performed per draft NRC rule making requiring the use of Code Case N729-1 to perform the UT and ET examinations of 100% of the CEDM and Vent line J-weld area. The examinations included a UT and ET examination from the ID of each nozzle in the J-weld area. In addition, all of the nozzles on the OD and all the J-weld surfaces were ET examined.

PVNGS UNIT 3 - REFUELING 10 (U3R10) ending in April, 2003

The examinations performed in Unit 3 yielded no detectable defects, no visual indications of leakage on the reactor vessel vent line and no detection of leakage into the interference fit zone of the ninety seven control element drive mechanism nozzles. As a result, no repairs were required.

PVNGS UNIT 3 - REFUELING 11 (U3R11) ending in December, 2004

The visual examination of the bare-metal surface of the reactor head found no evidence of boron or corrosion. No cleaning of the RPV head was necessary during U3R11. Potential boric acid leak sites from pressure retaining components above the RPV head were examined. Two leak sites at CEDM vents were identified. No active leak was identified. The dry boric acid deposit stayed in the area of the vents and no carbon steel was affected.

The non-visual NDE was performed for the head vent nozzle inspection following the modification of the head vent nozzle to permanently relocate the internal orifice. Upon removal of the orifice a surface examination (eddy current) of the J-groove weld and inside nozzle surface was performed as required. No flaws were found during this examination.

Conclusion

The continued implementation of the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.6 Flow-Accelerated Corrosion

Program Description

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

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

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

NUREG-1801 Consistency

The Flow-Accelerated Corrosion program is an existing program that~~, following enhancement, will be~~ is consistent with exception to NUREG-1801, Section XI.M17, "Flow-Accelerated Corrosion".

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program – Element 1 and Detection of Aging Effects – Element 4

NUREG-1801, Section XI.M17 indicates the FAC Program relies on implementation of EPRI guidelines in NSAC-202L-R2. However, the guidelines provided in the governing procedure 81DP-0RA02 were developed based on the recommendations provided in the EPRI Guideline NSAC-202L-R3.

The new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations are intended to refine and enhance those of previous revisions without contradictions to ensure continuity of existing plant FAC programs

Enhancements

None.

~~Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:~~

~~Scope of Program – Element 1, Detection of Aging Effects – Element 4, Monitoring and Trending – Element 5, and Acceptance Criteria – Element 6~~

~~The program procedure will be enhanced to clarify the guidance for susceptible small-bore piping components.~~

~~Acceptance Criteria – Element 6 and Corrective Actions – Element 7~~

~~The program procedure will be enhanced to verify the trace chromium content of the carbon steel pipe replacement.~~

Operating Experience

Review of the work orders (from May 1996 through present) showed that there has been no reported FAC-related leak or rupture at PVNGS for the components within the scope of license renewal. Most of the work orders identified the effect of wall thinning during the FAC program inspections. There were cases where the allowable thickness determined in accordance with the program guidelines were reached and more rigorous stress analyses were performed to justify continued service and to postpone the replacement. Problems identified during implementation of the program activities were not significant to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. Industry and plant operating experience were reviewed for applicability and adjustment of the outage inspection list was determined in accordance with program guidelines.

For previous refueling outages from R~~9~~10 through R~~12~~14 of all three units, ~~80~~66 to ~~160~~166 locations of large-bore systems were selected for inspection before the outage. The scope was expanded if necessary based on UT findings. An inspection location included the subject component (such as an elbow) and its adjacent area (such as upstream and downstream piping). For small-bore systems, 16 to ~~65~~52 inspections were selected before the outage. The scope was also expanded if necessary based on UT findings. The replacements for each outage are scheduled on proactive basis, determined by the projected remaining service life based on FAC analyses and by programmatic strategy based on industry experience and cost comparison to further inspections. The selections of FAC-resistance materials are stainless steel, chrome-moly alloy, or carbon steel with trace chromium content > 0.1%. Baseline inspections were performed for selected replacement locations of chrome-moly alloy and carbon steel with trace chromium content > 0.1%.

Conclusion

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

B2.1.8 Steam Generator Tube Integrity

Program Description

The scope of the Steam Generator Tube Integrity program includes the preventive measures, degradation assessment, steam generator inspection, integrity assessment, primary and secondary chemistry controls, leakage monitoring, and required maintenance and repair activities necessary to manage cracking, denting, wall thinning, and loss of material. The aging management measures employed include, non-destructive examination, visual inspection, sludge removal, tube plugging, in-situ pressure testing and maintaining the chemistry environment by removal of impurities and addition of chemicals to control pH and oxygen. Non-destructive Examination (NDE) inspection scope and frequency, and primary to secondary leak rate monitoring are conducted consistent with the requirements of PVNGS Technical Specifications. PVNGS evaluates tube integrity in accordance with the structural integrity performance criteria specified in Technical Specifications which encompasses and exceeds the requirements of Regulatory Guide 1.121. In addition, Technical Specifications include accident induced leakage performance criterion and operational leakage performance criterion. The steam generator management practices are consistent with NEI 97-06, "*Steam Generator Program Guidelines*".

Guidance for steam generator management is specified in station procedures. This guidance is consistent with the PVNGS Technical Specification requirements for steam generator tube integrity and primary to secondary leakage limits. The PVNGS steam generator inspection frequency is evaluated as part of the Degradation Assessment performed prior to each inservice inspection consistent with the Technical Specification requirements for the observed degradation mechanism. Plugging criteria for removing tubes from service are consistent with Technical Specifications.

Tube support degradation is monitored by the presence of normal support signals at expected tube locations and by visual inspection of the secondary side. The PVNGS steam generator management procedure specifies that steam generators will be visually inspected, as required, on the secondary side at the accessible portions of the following locations: tube sheet region, both hot and cold leg, tube supports, flow distribution plate, and upper steam drum internals.

Aging management activities for steam generator tubing integrity are controlled by station procedures. The steam generators are also monitored under the Maintenance Rule (10 CFR 50.65) as implemented by station procedures. The Steam Generator Tube Integrity program was developed from and is consistent with NEI 97-06, "*Steam Generator Program Guidelines*". PVNGS procedural guidance includes performance criteria for tube structural integrity, operational leakage and accident induced leakage that are consistent with NEI 97-06 and the PVNGS Technical Specifications. Procedural guidelines are also provided for monitoring and maintenance including plugging criteria, plug inspection requirements and inspection requirements for tube supports. The training and qualification standards for personnel engaged in the acquisition and/or evaluation of steam generator NDE activities are specified in a station administrative procedure, and inspection practices are consistent with EPRI ~~1003138~~1013706, "*PWR Steam Generator Examination Guidelines*". PVNGS programmatic guidance also requires that each inspection be based on a degradation assessment that considers active, relevant and potential damage mechanisms.

NUREG-1801 Consistency

The Steam Generator Tube Integrity program is an existing program that is consistent with NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity".

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Steam Generator Tube Integrity program has been developed to be consistent with NEI 97-06, and it benefits from the industry operating experience available when the initiative was issued as well as the EPRI guidelines it endorses. Station procedural guidance requires that the Steam Generator Degradation Assessment for PVNGS be updated every operating cycle to incorporate the latest industry and plant-specific experience regarding steam generator degradation mechanisms.

NRC Information Notice 97-88 addressed the importance of recognizing the potential for degradation in areas that have not previously experienced tube degradation and the importance of licensees to assess the significance of indications with respect to the qualification of the inspection techniques and the manner in which the indications were detected. The PVNGS Steam Generator Degradation Assessment evaluates industry experience as well as PVNGS experience to identify active, relevant and potential tube damage mechanisms. The inspection sample size, location and method are developed to fully address active mechanisms and provide assurance that relevant and potential mechanisms will be identified if they become active at PVNGS. The inspection expansion criteria take into account both increasing the area inspected when degradation is found and changing the technology used to accurately examine ambiguous or unexpected degradation.

PVNGS Units 1, 2 and 3 are two loop Combustion Engineering (CE) plants with two identical replacement steam generators designed by ABB/CE which are considered a modified CE System 80 design. The original steam generators were replaced in Units 1, 2, and 3 during the fall of 2005, 2003, and 2007, respectively. Each steam generator has a total of 12,580 Alloy 690 thermally treated tubes. The tubes are hydraulically expanded into the tubesheet for the entire tubesheet thickness. The tube support system is similar to the original design, and like the original design is fabricated from 409 ferritic stainless steel. To minimize the potential for stress corrosion cracking, in addition to the tubing material change, the U-bend region in the first 17 rows were stress relieved after bending.

Industry experience has shown that tube damage in replacement steam generators typically occurs from loose parts and support wear.

Wear is the only active damage mechanism in the PVNGS Replacement Steam Generators (RSGs) ~~as of U1R13 and U2R13,~~ and specifically wear as the result of interaction of tubing with the tube supports. Most of the wear indications ~~were~~have been observed in a region around the stay cylinder and at either ~~of~~ the ~~Batwings~~Diagonal Supports or Vertical Supports (Primarily VS3).~~Strap (VS3).~~

As of the end of the ~~U1R13 and U2R13~~U1R14, U2R15 and U3R14 outages no corrosion degradation has been detected in any of the PVNGS replacement steam generator tubes.

Due to certain historically observed wear phenomenon, PVNGS has employed conservative administrative plugging criteria related to support wear mechanisms. For example, support wear indications are removed for wear rate greater than or equal to 35% for a normal operating cycle if no previous wear is identified. This plugging criterion is designed to ensure that the structural and accident leakage performance criteria specified in the PVNGS Technical Specifications are not exceeded in the subsequent operating cycle. It was expected, based on RSG redesign, that the conditions necessary to generate high wear rates in the Batwing Stay Cylinder (BWSC) and Cold Leg Corner (CLC) regions were eliminated. While this was clearly the case for CLC wear, the RSG inspection results during the initial inspection in Unit 2 (U2R12) indicated that the RSG's continued to exhibit similar wear conditions within the BWSC region. As a result of these findings, a decision was made prior to Unit 1 and Unit 3 RSG installation to plug and stake all of the "frontline" BWSC tubes. The subsequent inspections during U2R13, U1R13, U2R14, U1R14, U3R14 and U2R15 have indicated that the BWSC wear issue exists in the RSG's of all 3 PVNGS units.~~in Unit 2 during U2R12 and U2R13 indicated that, for at least Unit 2, the RSGs continued to exhibit similar wear conditions within the BWSC region. However a similar result was not observed in Unit 1. There are several possible explanations for these results. These include:~~

~~A decision was made prior to Unit 1 RSG installation to plug and stake all the "frontline" BWSC tubes. These are the tubes most likely to be affected by BWSC wear. As these tubes were plugged, no NDE data could be collected to confirm the presence of BWSC wear. However, it should be noted that in Unit 2, BWSC wear was observed randomly throughout the affected region (with the largest wear observed in the frontline tubes). No BWSC wear was observed, at all, in the Unit 1 RSGs.~~

~~During discussions with Westinghouse, following U2R12, it was suggested that fabrication issues resulting in less than expected tube to tube support interaction may be a reason for the unexpected observed wear. It is possible that in Unit 1, improved alignment may be resulting in less wear.~~

On February 19, 2004 Unit 2 was operating at full power when radiation monitors displayed indications of a low level primary to secondary leak. Shortly thereafter the leak rate was calculated to be 11.8 gallons per day, even though grab samples indicated 3 gallons per day, and the decision was made to shut the unit down to find and repair the leak.

After cooling the plant down and performing tests, one SG tube was found to be leaking and was plugged. Further analysis showed that the cause of the leak was from a puncture received from a wood screw that was used in the construction of the shipping crates for the tubes when the steam generators were being manufactured. The tubes were placed in the crate and the crate assembled around them. One screw that was used near the outer diameter of the top of the tube bend protruded through the wood and began to puncture the tube material. The screw did not completely penetrate the tube and the unit was operated from its post-outage startup to this date when the tube finally began leaking. Contamination to the secondary plant was minimal and the unit entered Mode 1 on March 9, 2004. Corrective actions put in place after the event prevented recurrence in the Unit 1 and 3 replacement steam generators.

Conclusion

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

B2.1.9 Open-Cycle Cooling Water System

Program Description

The Open-Cycle Cooling Water System program manages loss of material and reduction of heat transfer for components exposed to the raw water of the open-cycle cooling water system. The program includes surveillance techniques and control techniques to manage aging effects caused by biofouling, corrosion, erosion and silting in the open-cycle cooling water system and in structures and components cooled by the open-cycle cooling water system. The only safety-related open-cycle service water system is the essential spray pond system. Essential spray ponds serve as the ultimate heat sink. In addition to the essential spray pond system, the open-cycle cooling water program also addresses the essential cooling water system heat exchangers that are administratively located within the essential cooling water system license renewal boundary and the emergency diesel generator jacket water, emergency diesel generator fuel oil, emergency diesel generator lube oil and emergency diesel generator turbo air intercooler heat exchangers that are administratively located with the emergency diesel generator system license renewal boundary together with their associated components that are exposed to raw water supplied by the essential spray ponds system. The program is consistent with PVNGS commitments as established in responses to Generic Letter 89-13.

The surveillance techniques utilized in the Open-Cycle Cooling Water program include visual inspection and Non-Destructive Examination (NDE) of selected components together with thermal and hydraulic performance monitoring of heat exchangers and of the essential spray pond system as an integrated whole. The control techniques utilized in the Open-Cycle Cooling Water program include (1) water chemistry controls to mitigate the potential for the development of aggressive cooling water conditions, (2) flushes and (3) physical and/or chemical cleaning of heat exchangers and of the Essential Spray Ponds to remove fouling and to reduce the potential sources of fouling.

NUREG-1801 Consistency

The Open-Cycle Cooling Water System program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI, M20, "Open-Cycle Cooling Water System".

Exceptions to NUREG-1801

None

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Detection of Aging Effects – Element 4 and Acceptance Criteria – Element 6

Clarify guidance in the conduct of ~~heat exchanger and~~ piping inspections using NDE techniques and related acceptance criteria.

Operating Experience

PVNGS has experienced fouling of safety related coolers and heat exchangers due to inadequate chemistry control. In 1994, PVNGS implemented a new chemistry control program for the emergency spray pond system to control corrosion and prevent fouling of the safety-related components. Throughout the period of 1994 through May 2006, PVNGS made a series of changes to this program which created a chemical environment that was progressively more conducive to fouling of the heat exchangers which were relied upon to transfer heat from the reactor, containment, diesel generators, and safety-related equipment rooms to the ultimate heat sink. The foulant was determined to be a buildup of excess chemicals which were added as part of the chemistry control program. Years of test results showed degraded heat exchanger performance, numerous heat exchanger inspections which documented chemical buildup, and an increasing need to clean the heat exchangers more frequently. In May 2006 degraded performance was observed in all trains in all three units. Because of design margins, only Unit 2 Train B essential cooling water system heat exchanger was identified where fouling may have been sufficient to cause a loss of safety function.

As a result of an NRC inspection related to this operating history, the NRC concluded that there were five violations of NRC requirements, characterized as performance deficiencies. Upon final evaluation, the NRC determined that because these violations were of very low safety significance, had been entered into the corrective action program, the root-cause had been identified, and appropriate corrective actions had been taken, they were considered non-cited violations.

The following immediate corrective actions were taken to return the effected systems to full operability:

- The essential spray ponds system chemistry was corrected.
- Essential cooling water system heat exchangers were cleaned in all three units.
- Diesel generator intercoolers were cleaned in all three units and diesel generator test frequency was increased until it was determined that the immediate corrective actions were effective.
- Procedures were revised to require a work order to be generated to clean any emergency diesel generator intercooler if temperature exceeds 120° F.
- The spray ponds were cleaned in all three units.

- Additional cleaning and inspections of the diesel generator and essential cooling water heat exchangers were scheduled.

The following corrective actions were taken to ensure root-cause issues were corrected:

- *Chemistry control program was revised to establish appropriate limits and to* increase sampling frequencies.
- Revised essential cooling water heat exchanger procedures to ensure thermal performance was adequately evaluated
- Established controls that required changes to the chemistry control program to undergo 10 CFR 59 reviews
- Actions were taken to reinforce the need to maintain a "low threshold" with respect to corrective action initiation.
- Corrected the use of computer models that predicted calcium phosphate scale

Conclusion

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

B2.1.12 Fire Protection

Program Description

The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pumps, and the CO_2 and halon fire suppression systems, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated floors are performed to ensure that they can perform their intended function.

The Fire Protection program manages aging by a visual inspection on ten percent of each type of penetration seal at least once every 18 months. This sample set method ensures that each penetration seal is inspected at least once every 15 years.

The Fire Protection program manages aging by a visual inspection every 18 months of the fire barrier walls, ceilings, and floors, including coating and wraps of Thermo-lag enclosures, examining for any signs of aging such as cracking, spalling, and loss of material.

The Fire Protection program manages aging by drop testing on ten percent of all accessible fire dampers on an 18 month basis.

The Fire Protection program manages aging by performing visual inspections every 18 months on fire-rated doors to verify the integrity of door surfaces and for clearances to detect aging of the fire doors prior to the loss of intended function.

The diesel-driven fire pumps are under observation during performance tests such as flow tests, start/run tests for detecting any aging of the fuel supply line. The fuel oil supply line is also managed by the Fuel Oil Chemistry program (B2.1.14) and External Surface Monitoring Program (B2.1.20).

A visual inspection and function test of the halon and CO_2 fire suppression systems is performed every 18 months.

NUREG-1801 Consistency

The Fire Protection program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.M26, “Fire Protection”.

Exceptions to NUREG-1801

Program Elements Affected

Parameters Monitored or Inspected - Element 3 and Detection of Aging Effects – Element 4

NUREG-1801 recommends a visual inspection and function test of the halon and CO_2 systems every six months. The PVNGS procedures for visual inspections and function testing of the halon and CO_2 fire suppression systems are performed every 18 months (excluding dampers which are integrity validated every 54 months per TSR 3.11.103.6 and TSR 3.11.106.6) per Technical Requirements Manual Surveillance Requirements (TSR) 3.11.106.4, and 3.11.103.4, respectively. ~~This procedural function test would~~ These functional tests will identify any mechanical damage of the halon and CO_2 fire suppression system that prevents the system from performing its intended function. The ~~18 month~~ test frequency is considered sufficient to ensure system availability and operability based on station operating history that indicates no loss of intended function due to aging. A review of the past ten years of operating experience and corrective action documentation has shown no degradation or loss of intended function between test intervals.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Parameters Monitored or Inspected – Element 3, Detection of Aging Effects – Element 4, Monitoring and Trending –Element 5, and Acceptance Criteria – Element 6

Procedures will be enhanced to state trending requirements for the diesel-driven fire pump ~~and to include visual inspection of the fuel supply line to detect degradation~~.

Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the CO_2 system discharge nozzles.

Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors.

Operating Experience

Plant operating experience indicates that there have been instances of Thermo-Lag degradation and cracking. These portions of affected Thermo-Lag envelopes have been reworked according to PVNGS specification. PVNGS has also experienced door skin cracks. These have been weld repaired according to specification.

During May of 2005, a fire protection audit was performed by members of APS and other industry representatives. The audit team observed current conditions and installations of the CO2 and halon suppression systems during walk-downs of selected fire zones. All systems were found in good condition. Multiple walkdowns per unit were conducted to examine the current condition of existing fire barriers in the Unit 1 control building, the Unit 2 turbine building, and the Unit 3 auxiliary building. There was one adverse condition identified in the Unit 3 auxiliary building where copper piping was penetrating the floor barriers. The audit team found no degraded conditions (e.g., cracks, gouges, holes in material, joint/seal gaps) of installed electrical raceway fire barriers.

In September of 2006, it was discovered that a carbon steel pipe nipple was in need of replacement due to galvanic corrosion and was subsequently replaced. The nipple was located between a galvanized tee and a brass valve. This event is representative of the PVNGS experience of detecting degradations and leakage in time to take corrective action prior to the loss of intended function.

During the 2007 fire protection audit, a concern was raised for the need of a plan to identify fire protection equipment obsolescence issues. Design modifications have been identified to address these issues.

Conclusion

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

B2.1.14 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry program manages loss of material on the internal surface of components in the emergency diesel generator (EDG) fuel oil storage and transfer system, diesel fire pump fuel oil system, and station blackout generator (SBOG) system. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) visual inspection of internal surfaces during periodic draining and cleaning, (d) ultrasonic wall thickness measurements of fuel oil tanks if there are indications of reduced cross sectional thickness found during the visual inspection, (e) inspection of new fuel oil before it is introduced in the fuel oil tanks, and (f) one-time inspections of a representative sample of components in systems that contain fuel oil by the One-Time Inspection Program.

Fuel oil quality is maintained by monitoring and controlling fuel oil contaminants in accordance with applicable ASTM Standards. This is accomplished by periodic sampling and chemical analysis of the fuel oil inventory at the plant and sampling, testing, and analysis of new fuel oil prior to introduction into the fuel oil storage tanks. Initial samples of new fuel oil are inspected for entrained foreign material and water as precautions during the delivery process to avoid introducing contaminants. If a sample appears to be unsatisfactory, delivery is discontinued or not allowed.

The One-Time Inspection program (Section B2.1.16) will be used to verify the effectiveness of the Fuel Oil Chemistry program.

NUREG-1801 Consistency

The Fuel Oil Chemistry program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.M30, "Fuel Oil Chemistry".

Exceptions to NUREG-1801

Program Elements Affected

Preventive Actions - Element 2

Stabilizers and corrosion inhibitors are not added to the diesel fuel based on the plant operation experience with negligible underground temperature swings, an arid outdoor environment, and operating experience showing the historical absence of water in the EDG fuel oil. Fuel oil quality is ~~maintained~~ verified through periodic sampling.

Parameters Monitored or Inspected - Element 3 and Acceptance Criteria -Element 6

NUREG-1801 states within Element 3, in part, the ASTM Standards D1796 and D2709 are used for determination of water and sediment contamination in diesel fuel. PVNGS Technical Specification 5.5.13 requires use of ASTM Standard D1796-83 only.

Monitoring and Trending –Element 5

Water has never been discovered within the EDG fuel oil system, and therefore biological activity is not monitored. PVNGS Technical Specification Bases for Surveillance Requirement 3.8.1.5 state that removal of water is the most effective means of controlling microbiological fouling.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Scope of Program – Element 1, Parameters Monitored or Inspected – Element 3, and Monitoring and Trending –Element 5

Procedures will be enhanced to extend the scope of the program to include SBOG fuel oil storage tank and SBOG skid fuel tanks.

Preventive Actions - Element 2 and Detection of Aging Effects – Element 4

Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, SBOG fuel oil storage tank~~s~~, and SBOG skid fuel tanks.

Detection of Aging Effects – Element 4

Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, ~~and~~ SBOG fuel oil storage ~~tanks~~ tank, and SBOG skid fuel tanks. The one-time UT or PEC examination on the tank bottoms will be performed before the period of extended operation.

Operating Experience

PVNGS has no operating experience resulting in MIC in EDG fuel oil. Also, operating experience has shown negligible underground temperature swings and absence of water in the EDG fuel oil.

In 2005, during the U2R12 refueling outage, strainers downstream of the EDG fuel oil day tank were found to be clogged. The cause was determined to be a buildup of sediment in

B2.1.17 Selective Leaching of Materials

Program Description

The Selective Leaching of Materials program manages the loss of material due to selective leaching for copper alloy >15% zinc (brass), copper alloy >8% aluminum (aluminum-bronze), and gray cast iron components exposed to closed-cycle cooling water, demineralized water, secondary water, ~~and raw water~~ raw water and wetted gas within the scope of license renewal. Components susceptible to selective leaching are in the auxiliary steam, diesel generator, essential chilled water, ~~essential cooling water~~, essential spray ponds, and fire protection systems.

A one-time inspection of a selected sample of components internal surfaces ~~will be~~ is performed. Visual and/or mechanical methods ~~will~~ determine whether loss of material due to selective leaching is occurring. If these inspections detect dezincification, de-alloying, or graphitization, which are indications of selective leaching, then a follow-up examination/evaluation ~~will be~~ is performed. The examination/evaluation may require confirmation of selective leaching with a metallurgical evaluation which may include microstructure examination. The sample size of the system/material/environment combination may be expanded based on the results of the evaluation and testing. If indications of selective leaching are confirmed, follow up examinations/evaluations ~~will be~~ are performed.

~~A station procedure will implement the Selective Leaching of Materials program. The initial visual inspections and evaluations will be completed prior to the period of extended operation.~~

NUREG-1801 Consistency

The Selective Leaching of Materials program is an existing program that is ~~a new program that, when implemented, will be~~ consistent with exception to NUREG-1801, Section XI.M33, "Selective Leaching of Materials".

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program – Element 1, Preventive Actions – Element 2, Parameters Monitored or Inspected – Element 3, and Detection of Aging Effects – Element 4

NUREG-1801, Section XI.M33 recommends hardness testing of sample components in addition to visual inspections. However, a qualitative determination of selective leaching ~~will be~~ is used in lieu of Brinell hardness testing for components within the scope of the PVNGS Selective Leaching of Materials program. The exception involves the use of examinations, other than Brinell hardness testing identified in NUREG-1801 to identify the presence of selective leaching of materials. The exception is justified, because (1) hardness testing may not be feasible for most components due to form and configuration ~~(e.g., heat exchanger tubes)~~ and (2) other mechanical means, e.g., scraping, or chipping, provide an equally valid means of identification.

Additionally, hardness testing ~~will only provide~~ only provides definitive results if baseline values are available for comparison purposes. Specific material contents for copper alloys may not be known and gray cast irons may not have published hardness numbers. Without specific numbers for comparison, hardness testing would yield unusable results. In lieu of hardness testing, visual and mechanical inspections ~~will be~~ are performed on a sampling of components constructed of copper alloys (>15% zinc and >8% aluminum) and gray cast iron from various station system environments. Follow-up examinations or evaluations ~~will be~~ are performed on component material samples where indications of dezincification, de-alloying, or graphitization are visually detected and additional analysis as part of the engineering evaluation is required. The engineering evaluation may require confirmation with a metallurgical evaluation (which may include a microstructure examination).

Enhancements

None

Operating Experience

~~The Selective Leaching of Materials program is a new program that is a one-time inspection with no plant-specific program operating experience history.~~

The accelerated de-alloying of aluminum-bronze (copper alloy >8% aluminum), caused by Microbiologically Induced Corrosion (MIC), which was the subject of Information Notice 94-59 regarding selective leaching, is documented. The PVNGS open-cycle cooling water systems are chemically treated with biocides to prevent the growth of MIC causing bacteria and systems, not in continuous use, are recirculated periodically to ensure adequate chemical mixing is maintained. ~~Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.~~

Conclusion

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

B2.1.18 Buried Piping and Tanks Inspection

Program Description

The Buried Piping and Tanks Inspection program manages loss of material on external surfaces of buried components in the following systems: chemical and volume control, condensate storage and transfer, diesel fuel storage and transfer, domestic water, fire protection, ~~WRF~~ SBOG fuel system, service gas and essential spray ponds. Opportunistic visual inspections will monitor the condition of protective coatings and wrappings found on carbon steel, gray cast iron or ductile iron components and assess the condition of stainless steel components with no protective coatings or wraps. Any evidence of damaged wrapping or coating defects is an indicator of possible corrosion damage to the external surface of the components.

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended operation. Within the ten year period prior to entering the period of extended operation an opportunistic or planned inspection will be performed. The Buried Piping and Tanks Inspection program requires a planned inspection within the first ten years of the period of extended operation if an opportunistic inspection has not been performed within this ten year period.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection program is a new program that, when implemented, will be consistent with exception to NUREG-1801, Section XI.M34, "Buried Piping and Tanks Inspection".

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program – Element 1 and Acceptance Criteria- Element 6

NUREG-1801, Section XI.M34 scope only includes buried steel piping and components. However, PVNGS also includes stainless steel in their buried piping program that will be managed as part of this aging management program.

Scope of Program – Element 1, Preventive Actions – Element 2, and Acceptance Criteria- Element 6

NUREG-1801, Section XI.M34 relies on preventive measures such as coatings and wrappings. However, portions of buried stainless steel piping may not be coated or wrapped. Inspections of buried piping that is not wrapped will inspect for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion.

Enhancements

None

Operating Experience

The Buried Piping and Tanks Inspection program is a new program. Degradation of buried components was addressed at PVNGS during an inspection program in September 2002. Observations of this inspection program include:

During the past several years, leaks developed in various buried piping segments, which potentially threaten the continuous operation of PVNGS. These leaks collectively indicated a negative trend in the overall integrity of the buried pipe.

Inspection and maintenance activities were implemented in order to address overall integrity of the buried pipe. Determination of system priorities and development of a draft inspection plan for each of the evaluated systems was developed.

The applicable systems with piping installed below grade were evaluated and assigned ranking based on priority. The majority of these evaluated buried piping systems have very little or no identified potential for degradation.

The majority of the systems evaluated in the inspection program are not within the scope of license renewal. The PVNGS corrective action documentation to date has shown that, for the systems within the scope of license renewal, degradation has been found primarily in the fire protection system. Fire protection system has had localized degradation in excess of the minimum wall requirement of 40% nominal wall thickness. The designated segments of the degraded ductile iron piping have been replaced by fiberglass reinforced plastic piping. The fire protection system has not experienced a failure that affected the ability of the plant to achieve and maintain safe shutdown in the event of a fire. To date, the actual pipe failures of the underground fire protection system have been isolated and repaired without adversely affecting any fire protection water suppression system.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the Buried Piping and Tanks Inspection program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.19 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Program Description

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of stainless steel ASME Code Class 1 piping less than or equal to 4 inches. ~~This program is a part of the Risk-Informed Inservice Inspection (RI-ISI) program.~~

For ASME Code Class 1 small-bore piping, ~~the RI-ISI program requires volumetric examinations (by ultrasonic testing) on selected weld locations to detect cracking. Weld locations are selected~~volumetric examinations (by ultrasonic testing) will be performed on selected butt weld locations to detect cracking. Small-bore weld locations are selected for examination based on the guidelines provided in EPRI TR-112657. Volumetric examinations are conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3131 and IWB-2430 for butt welds. Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. If a qualified volumetric examination procedure for socket welds endorsed by the industry and the NRC is available and incorporated into the ASME Section XI Code at the time of PVNGS small-bore socket weld inspections then volumetric examinations will be conducted on small-bore socket welds as part of the PVNGS program. ~~The fourth interval of the ISI program will provide the results for the one time inspection of ASME Code Class 1 small-bore piping.~~

If evidence of an aging effect is revealed by a one-time inspection, evaluation of the inspection results will identify appropriate corrective actions.

This Program will be implemented and inspections completed and evaluated prior to the period of extended operation.

~~In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI Program is updated eachsuccessive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.~~

NUREG-1801 Consistency

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program ~~is an existing program that is~~is a new program that, when implemented, will be consistent, with exception to NUREG-1801, Section XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping".

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program - Element 1

~~The PVNGS risk-informed process, examination requirements are performed consistent with EPRI TR-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure", Rev. B-A, instead of EPRI Report 1000701, "Interim Thermal Fatigue~~

~~Management Guideline" (MRP-24).~~Guidelines from EPRI TR-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Rev. B-A, were used for identifying susceptible piping instead of EPRI Report 1000701, "Internal Thermal Fatigue Management" Guidance (MRP-24). Guidelines for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration that are provided in EPRI Report 1000701 are also provided in EPRI TR-112657. The recommended inspection volume for welds in EPRI Report 1000701 are identical to those for inspection of thermal fatigue in RI-ISI programs; thus, the PVNGS risk-informed process examination requirements meet the requirements of NUREG-1801 and no enhancements are required.

Enhancements

None.

Operating Experience

In order to estimate the extent of the problem of cracking in Class 1 piping socket welds, Nebraska Public Power District (NPPD) performed a search of LERs in the NRC ADAMS database relating to this topic. They found 22 examples. These events were the result of high-cycle fatigue cracking due to vibration or weld defects during installation. As noted by NPPD, cracking due to high-cycle fatigue is the result of improper design or installation that creates an unanalyzed condition that will lead to failure of the component early in life if not corrected. It is not related to the effects of aging. Typical industry response to cracking caused by high-cycle fatigue is to modify the design to prevent recurrence including using improved socket welds and changing the installation to eliminate the vibration.

PVNGS has experienced cracking of stainless steel ASME Code Class 1 piping less than or equal to NPS 4. A hair-line weld failure was caused by cyclic fatigue due to vibration combined with being improperly supported on a shutdown cooling suction line. Piping modifications have reduced the excessive vibration. A review of the second 10-year ISI Interval Summary Reports for Units 1, 2 and 3 indicates there were no code repairs or code replacements required for continued service of ASME IWB Code components during the second 10-year ISI Interval.

Conclusion

The implementation of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program ~~during the 4th Inservice Inspection Interval~~ will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.22 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, loss of material, and hardening and loss of strength. The internal surfaces of piping, piping components, ducting and other components that are not covered by other aging management programs are included in this program.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses the work control process to conduct and document inspections. The program will perform visual inspections to detect aging effects that could result in a loss of component intended function. The visual inspections will be conducted during periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance. Additionally, visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of both internal and external surfaces of elastomers. The program also includes volumetric evaluation to detect stress corrosion cracking of the internal surfaces of stainless steel components exposed to diesel exhaust.

Within 10 years before entering the period of extended operation, a review will be conducted to determine the number of inspection opportunities afforded by the work control process for all systems within the scope of this program. In the vast majority of cases, it is expected that the number of work opportunities existing will be sufficient to detect aging and provide reasonable assurance that intended functions are maintained. For those systems or components where inspections of opportunity are insufficient, an inspection will be conducted prior to the period of extended operation to provide reasonable assurance that the intended functions are maintained.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that, when implemented, will be consistent with exception to NUREG-1801, Section XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components".

Exceptions to NUREG-1801

Program Elements Affected:

Scope of Program – Element 1; Parameters Monitored or Inspected – Element 3; Detection of Aging Effects – Element 4; and Monitoring and Trending – Element 5.

NUREG-1801 XI.M38 provides for a program of visual inspections of the internal surfaces of miscellaneous steel piping and ducting components to ensure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. The exceptions to NUREG-1801, XI.M38 are an increase to the scope of the materials inspected to include stainless steel, aluminum, copper alloy and elastomers in addition to steel and an increase to the scope of aging effects to include cracking in stainless steel and hardening and loss of strength for elastomers. Additionally, visual inspections may be augmented (1) by physical manipulation to detect hardening and loss of strength of elastomers and (2) by surface or volumetric evaluation to detect stress corrosion cracking of the internal surfaces of stainless steel components exposed to diesel exhaust.

Enhancements

None

Operating Experience

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program. Therefore no programmatic operating experience has been gained. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.23 Lubricating Oil Analysis

Program Description

The Lubricating Oil Analysis program manages loss of material and reduction of heat transfer for components within the scope of license renewal that have surfaces exposed to lubricating and hydraulic oils. The program will ensure the lubricating and hydraulic oil environment in mechanical systems is maintained to the required quality. The program monitors and controls oil contaminants, primarily water and particulates, within acceptable limits, thereby preserving an environment that is not conducive to aging effects. Monitoring and trending of oil analysis results identifies the potential for component aging before loss of component intended function occurs. The program includes acceptance criteria based on vendor and industry guidelines.

Plant procedures implement sampling methods, lubricant test methods and lubricant test data evaluation requirements. Sample schedules are established and managed within the plant Reliability Centered Maintenance and Preventative Maintenance Program.

The One-Time Inspection program (Section B2.1.16) will be used to verify the effectiveness of the Lubricating Oil Analysis program.

NUREG-1801 Consistency

The Lubricating Oil Analysis program is an existing program that is consistent with exception to NUREG-1801, Section XI.M39, "Lubricating Oil Analysis".

Exceptions to NUREG-1801

<u>Program Elements Affected</u>

Parameters Monitored or Inspected – Element 3; Acceptance Criteria- Element 6

NUREG-1801 recommends that lubricating oil in components subject to periodic oil changes be tested using particle-counting test methods to detect evidence of abnormal wear rates or excessive corrosion. <u>There are three types of particle counting performed at PVNGS: particle count by Auto Counter for cleanliness, particle count by spectroscopy to measure ppm levels of metals and microscopic examination to characterize particles. The most appropriate method is used for each oil.</u> At PVNGS, the Lubricating Oil Analysis program conducts particle-counting <u>for cleanliness</u> on turbine oils but not on diesel engine oils due to limitations of the Auto Counter instrument. ~~the potential for interference by soot.~~ The Lubricating Oil Analysis program relies upon elemental analysis techniques as described in ASTM D6595 "*Determination of Wear Metals and Contaminants in Used Lubricating Oils or Used Hydraulic Fluids by Rotating Disc Electrode Atomic Emission Spectroscopy*" <u>to count wear metals</u>. ~~Elemental analysis techniques are considered to be a form of particle-~~

~~counting that also provides information about the metallurgy of the particles.~~ The use of elemental analysis <u>for wear metals</u> in lieu of particle counting <u>for cleanliness</u> ~~techniques~~ is deemed to provide a greater degree of insight into lubricant condition for the purpose of managing aging.

NUREG-1801 recommends that lubricating oil in components that are not subject to periodic oil changes be tested additionally for flash point in order to verify suitability for continued use. At PVNGS, the Lubricating Oil Analysis program considers flash point testing to provide indication of lubricating oil contamination by fuel oils. The Lubricating Oil Analysis program therefore requires flash point testing only for lubricating oils in components where the potential exists for contamination of the lubricating oil by fuel oil.

NUREG-1801 recommends that lubricating oil in components that are not subject to periodic oil changes be tested additionally for neutralization number. At PVNGS, the Lubricating Oil Analysis program tests diesel engine lubrication oils using the Total Base Number (BN) parameter for lubricant evaluations performed to assess the suitability of oil for continued use; Total Acid Number (AN) has been found to be of limited utility in evaluating engine oils for continued use, however, this test is used for evaluating the oils in other components for continued use.

Enhancements

None

Operating Experience

PVNGS site specific operating experience revealed no pattern of events involving loss of intended function as a result of aging effects related to lubricating oil contamination or degradation.

Reactor coolant pump bearing systems ~~which includes the pump thrust bearing and the oil overflow storage tank~~ - During the 1994-1997 time frame, abnormal water levels were measured in oil samples of 4 of the 12 pump bearings. Three of these were from Unit 2. When the water was discovered, corrective action was taken to remove the water and oil. Testing was performed until acceptable oil dryness could be established. The cause was determined to be an outage related cleaning practice that resulted in placing water in the oil. All 12 reactor coolant pump bearing systems have been ~~dry~~ <u>water-free</u> since the cleaning practice was changed.

Emergency diesel generator particulate (wear metal) condition - In July of 1999, abnormal wear metal levels were measured in the 2MDGAH01 engine oil. The test measurement indicated a step change in chrome. The cylinder liners were believed to be the most likely source of the wear metal. Boroscope inspection isolated the liner which was removed and replaced. Visual inspection post maintenance indicated axial wear in the form of scratches which caused narrow cuts through the chrome. The cause was determined to be a random event that occurred where the gaps in the rings were aligned.

Conclusion

The continued implementation of the Lubricating Oil Analysis program, supplemented by the One-Time Inspection program (B2.1.16), provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.25 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Program Description

The scope of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program includes the cables and connections used in sensitive instrumentation circuits with sensitive, high voltage low-level signals within the ex-core neutron monitoring system. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program manages embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance.

The purpose of this program is to provide reasonable assurance that the intended function of cables and connections used in instrumentation circuits with sensitive, low-level signals 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 are maintained consistent with the current licensing basis through the period of extended operation. In most areas, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment for those areas.

Calibration surveillance tests ~~will be~~ are used to manage the aging of the cable insulation and connections so that instrumentation circuits perform their intended functions. When an instrumentation channel is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable and connections. A review of the calibration results will be completed before the period of extended operation and every 10 years thereafter.

NUREG-1801 Consistency

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program is an existing program, that following enhancement, will be consistent with NUREG-1801, Section XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits".

Exceptions to NUREG-1801

None

Enhancements

Prior to the period of extended operation, the following enhancement will be implemented in the following program elements:

Scope of Program – Element 1~~,~~ and Detection of Aging Effects - Element 4 ~~, and Corrective Actions – Element 7~~

Procedures will be enhanced to identify license renewal scope and require an ~~engineering~~ evaluation of the calibration results ~~and to require that an action request be written when the loop cannot be calibrated to meet acceptance criteria~~.

Operating Experience

Industry operating experience has identified occurrences of cable and connection insulation degradation in high voltage, low level instrumentation circuits performing radiation monitoring and nuclear instrumentation functions. The majority of occurrences are related to cable and connection insulation degradation inside of containment near the reactor vessel or to a change in an instrument readout associated with a proximate change in temperature inside the containment.

A review of plant operating experience identified issues with ex-core noise and spiking. A root cause analysis was performed and corrective actions included system walkdowns and testing which identified cable and connection characterization. Continued coaxial connector replacements, utilization of ferrite beads, and improved grounding have been effective in improving overall performance.

Conclusion

The continued implementation of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program manages localized damage and breakdown of insulation leading to electrical failure in inaccessible medium voltage cables exposed to adverse localized environments caused by significant moisture simultaneously with significant voltage to ensure that inaccessible medium voltage cables not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended function.

All cable manholes that contain in-scope non-EQ inaccessible medium voltage cables will be inspected for water collection. The collected water will be removed as required. This inspection and water removal will be performed based on actual plant experience but at least every two years.

All in-scope non-EQ inaccessible medium voltage cables routed through manholes will be tested to provide an indication of the conductor insulation condition. A polarization index test as *described in* EPRI TR-103834-P1-2 *or other testing that is state-of-the-art at the time* the testing will be performed at least once every ten years. The first test will be completed before the period of extended operation.

The acceptance criteria for each test will be defined for the specific type of test performed and the specific cable tested. Periodic inspections of cable manholes, for the accumulation of water will minimize cable exposure to water. Corrective actions for conditions that are adverse to quality are performed in accordance with the corrective action program as part of the QA program. The corrective action program provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable.

Procedures will implement the aging management program for testing of the medium voltage cables not subject to 10 CFR 50.49 EQ requirements and the periodic inspections and removal of water from the cable manholes containing in-scope medium voltage cables not subject to 10 CFR 50.49 EQ requirements.

NUREG-1801 Consistency

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Industry operating experience has shown that cross linked polyethylene or high molecular weight polyethylene insulation materials, exposed to significant moisture and voltage, are most susceptible to water tree formation. Formation and growth of water trees varies directly with operating voltage.

PVNGS has not experienced a failure of any inaccessible medium voltage cables. PVNGS has experienced cases where medium voltage cable splices have been subjected to water intrusion resulting in low megger readings. PVNGS is in the process of implementing corrective actions to minimize the intrusion of water into manholes by identifying sources of water, elevating the top of a manhole, and increasing the inspection frequency of manholes found to have water to once every year.

During manhole walkdowns in 2009, one was found to contain water submerging the cables. Subsequent inspection of a connected manhole found additional water. A review of the history of these and connected manholes found recurring instances of water intrusion. Changes to the existing manhole inspection, dewatering program and PM basis documents are being evaluated to improve program effectiveness. Additionally, physical changes to the manhole found to contain water are scheduled.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program will provide reasonable assurance that aging effects will be managed so that the intended functions of the inaccessible medium voltage cables within the scope of license renewal are maintained during the period of extended operation.

B2.1.34 Nickel Alloy Aging Management Program

Program Description

The plant-specific Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all reactor coolant pressure boundary locations that contain Alloy 600, with the exception of steam generator tubing and reactor vessel internals. Aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (B2.1.8). Aging management of reactor vessel internals is addressed in Reactor Coolant System Supplement (B2.1.21). Aging management requirements for nickel alloy penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (B2.1.5) are included in this program. This program includes Alloy 600 reactor coolant pressure boundary locations in the reactor coolant system (RCS) and ESF systems. The term Alloy 600 is used throughout this program to represent Nickel Alloy 600 material and Nickel Alloy 82/182 weld metal. Non-Alloy 600 nickel components (e.g., welds made of Alloy 52/152) are subject to the ASME Section XI Inservice Inspection program (B2.1.1) requirements as indicated in the Program Plan.

The plant-specific Nickel Alloy Aging Management Program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at PVNGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB, ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6), ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4), and EPRI Report ~~1010087~~ 1015009 (MRP-139) issued under NEI 03-08 protocol. The ~~official review and incorporation of practices of EPRI Report 1010087 (MRP-139) is not currently complete and the~~ implementation schedule, per EPRI Report ~~1010087~~ 1015009 (MRP-139), is defined in the Program Plan. Mitigation techniques are implemented when appropriate to preemptively remove conditions that contribute to PWSCC. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw. Mitigation and repair/replace activities are partially complete with those detailed in EPRI Report ~~1010087~~ 1015009 (MRP-139). Historical operating experience was reviewed and operating experience is continually monitored to provide improvements and modifications to the Alloy 600 Program as needed.

Aging Management Program Elements

The results of an evaluation of each element against the 10 elements described in Appendix A of NUREG-1800, *"Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants"* are provided below.

Scope of Program – Element 1

With the exception of steam generator tubing, which is managed by the Steam Generator Tube Integrity Aging Management program (B2.1.8), and reactor vessel internals, all Alloy 600 reactor coolant pressure boundary locations in plant systems are included in the scope of this program. This program includes reactor coolant system (RCS) and ESF system locations. Aging management requirements for Alloy 600 penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Aging Management program (B2.1.5) are included in this program. The term Alloy 600 will be used throughout this program to represent Nickel Alloy 600 material and Nickel Alloy 82/182 weld metal.

The PVNGS Alloy 600 aging management program identifies the following Alloy 600 locations including dissimilar metal (DM) welds:

- RPV Upper Head Penetrations / 97 CEDMs', 1 Head Vent
- Bottom Mounted Instrument Nozzles (BMI) / 61 Incore Instrumentation Penetrations
- Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material
- RCS Piping Instrument Nozzles / 12 Cold Leg instrument nozzles per unit (SB-166 material), 8 RCP instrument nozzles per unit (SB-166 material), 8 Unit 2 Hot Leg pressure instrument nozzles (82/182) welds

<u>The original Unit 1 and Unit 3 reactor pressure vessel (RPV) heads are planned to be replaced during the refueling outages in 2010. The Unit 2 RPV head was replaced during 2R15 outage in Fall 2009.</u>

<u>All components penetrating the new heads and welds including the head vent will be replaced with Alloy 690.</u>

The pressurizer (PZR) instrument nozzles and heater sleeves have been replaced with Alloy 690 material.

With exception of 8 Unit 2 Hot Leg pressure instrument nozzles, the RCS Hot Leg instrument nozzles also have been replaced with Alloy 690 material.

Steam Generator tube sheet cladding and nozzle dam retaining ring Alloy 600 cladding are not reactor coolant pressure boundary components and are not included in the Nickel Alloy Aging Management Program.

A full structural weld overlay (FSWOL) with Alloy 690 was completed for the following Hot Leg and Pressurizer locations. The Hot Leg and Pressurizer welds are no longer considered to be composed of Alloy 600, since they are completely encased in Alloy 690.

- Pressurizer Spray
- Pressurizer Safeties
- Pressurizer Surge Line (Hot Leg and Pressurizer side)
- Shutdown Cooling 1 & 2 ~~(Unit 3 FSWO spring 2009 outage)~~

The dissimilar metal butt-welds which are addressed in this program are those greater than or equal to 1" NPS in locations operating at cold leg temperature or higher. The Alloy 600 material locations at lower than cold leg temperatures are not subject to increased augmented inspections/replacements at this time because of the lower PWSCC susceptibility at lower service temperatures.

The PVNGS Alloy 600 aging management program identifies the following RCS dissimilar metal butt welds:

- Safety Injection 1A 14" dia
- Safety Injection 1B 14" dia
- Safety Injection 2A 14" dia
- Safety Injection 2B 14" dia
- PZR Spray 1A 3" dia
- PZR Spray 1B 3" dia
- Drain Line 1A 2" dia
- Drain Line 1B 2" dia
- Drain Line 2A 2" dia
- Letdown Line 2" dia
- Charging Line 2" dia

Preventive Actions – Element 2

The plant-specific Nickel Alloy Aging Management Program includes many potential mitigation strategies that remove one or more of the three conditions that control primary water stress corrosion cracking (susceptible material, tensile stress field, supporting environment). Mitigation activities that have been successfully performed for at least one US PWR plant include weld overlays, replacement of Alloy 600 (as a pre-planned activity), and mechanical stress improvement process (MSIP). Weld overlays are being implemented for more susceptible DM welds and those with inspectability issues. This method provides structural reinforcement at the (potentially) flawed location, such that adequate load-carrying capability is provided by the overlay. MSIP is a mechanical process that places the component surface in contact with the primary water in a compressive state, thereby removing the tensile stresses needed for initiation of PWSCC.

The considerations used in the PVNGS program include selecting a mitigation strategy, options for the most cost effective management specific to each category of components and the optimal course of action. All aspects of this plan comply with industry and regulatory guidance for inspections and repairs.

The PVNGS program includes the recommended mitigation strategies for all of the Alloy 600 components at PVNGS. Specific mitigation strategies will be determined by plant-specific and industry operating experience and may include the following:

Component / Mitigation Strategy / Planned Replacements

Reactor Pressure Vessel (RPV) – Upper Head Penetrations

- RPV Upper Head Penetrations / None / RVH ~~replacements scheduled 2009-2010~~ Unit 2 RVH was replaced in 2009. Unit 1 and 3 RVH replacements are scheduled for 2010 refueling outages.

Reactor Pressure Vessel (PRV) – Bottom Mounted Instrument (BMI) Nozzles

- Bottom Mounted Instrument Nozzles (BMI) / Cold leg zinc injection, half-nozzle repair to be developed / None planned

Pressurizer Nozzles

- Pressurizer instrument nozzles (7 each unit) / None / Complete (replaced with Alloy 690 material)
- Pressurizer heater sleeves / None / Complete (replaced with Alloy 690 material)
- Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material / None / Complete (nozzles replaced with Alloy 690 material)

<u>Dissimilar Metal Welds</u>

- PZR Spray / Structural Weld Overlay / weld overlays implemented
- PZR Safeties / Structural Weld Overlay / weld overlays implemented Surge Line (HL and PZR Side) / Structural weld Overlay or MSIP / weld overlays implemented
- Pressurizer Surge Line (HL and PZR Side) / Structural weld Overlay or MSIP / weld overlays implemented
- PZR Spray 1A and 1B / Structural weld Overlay or MSIP / None
- Shutdown Cooling 1 and 2 / Structural weld, Overlay or MSIP / weld overlays implemented. ~~Unit 1 and Unit 2. Unit 3 planned Spring 2009~~
- Safety Injection lines / None / None
- Drain Line 1A and 1B / None / None
- Drain Line 2A / None / None
- Letdown Line / None / None
- Charging Line / None / None

<u>RCS Piping Instrument Nozzles</u>

- 27 Hot Legs (each unit) / None / Complete (replaced or plugged with Alloy 690 material)
- 8 Unit 2 Hot Leg pressure instrument nozzles (82/182 welds) / None / None planned
- 12 Cold Legs (each unit) / Cold leg zinc injection, half-nozzle repair to be developed / None planned
- 8 RCP Instrument Taps (each unit) / None / None planned

The Water Chemistry program (B2.1.2) provides preventive actions for monitoring and control of the supporting environment for PWSCC. Primary water chemistry changes such as zinc addition is being evaluated to improve resistance to PWSCC for locations that are not being replaced or mitigated by other means.

Parameters Monitored/Inspected – Element 3

The Nickel Alloy Aging Management Program monitors for cracking due to PWSCC. Loss of material due to boric acid wastage is also used as an indication of cracking due to PWSCC. Visual exams are used to detect evidence of leakage from reactor coolant pressure boundary components due to cracking and/or discontinuities and imperfections on the surface of the component. Surface examinations indicate the presence of surface discontinuities. Volumetric examination indicates the presence of cracking/discontinuities throughout the volume of material.

Detection of Aging Effects – Element 4

The Nickel Alloy Aging Management Program utilizes various visual, surface and volumetric inspection and examination techniques for early detection of PWSCC in Alloy 600 components.

Three types of visual exams are used:

1) VT-2 Exams which are conducted to detect evidence of leakage from pressure retaining components,

2) Bare Metal Visual (BMV) Exams which are similar to VT-2 exams but require removal of insulation to allow direct access to the metal surface,

3) Visual Exams which are conducted to assess the general condition of non-pressure boundary components.

Surface Exams are used to indicate the presence of surface discontinuities and are conducted by liquid penetrant or eddy current methods. Volumetric Exams indicate the presence of discontinuities throughout the volume of material and are conducted by radiographic, ultrasonic, or eddy current methods, or a combination.

The Palo Verde Nickel Alloy Program Plan provides visual, surface, and volumetric examinations to support the Nickel Alloy AMP. The following examinations are identified by the Palo Verde Nickel Alloy AMP for Alloy 600 locations. Inspections are for all units unless a unit specific inspection is indicated.

Component / Current Examinations

<u>Reactor Pressure Vessel (RPV) – Upper Head Penetrations</u>

- Requirement: ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6)
  Examination: BMV, surface and Volumetric (UT)

<u>Reactor Pressure Vessel (RPV) - Bottom Mounted Instrument (BMI) Nozzles</u>

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: BMV

Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: BMV

Dissimilar Metal Welds

- Requirement: EPRI Report ~~1010087~~ 1015009 (MRP-139) and ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: see below

- PZR Spray 1A and 1B / BMV

- Safety Injection lines / BMV, Volumetric

- Drain Line 1A and 1B / BMV

- Drain Line 2A / BMV

- Letdown Line / BMV

- Charging Line / BMV

RCS Piping Instrument Nozzles

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: see below

- 12 Cold Legs with SB-166 material (each unit) / BMV

- 8 RCP instrument taps (~~4 per~~ 2 per pump each unit) / BMV

- 8 Unit 2 Hot Leg pressure instrument nozzles (82/182 welds) / BMV

RPV Upper Head Penetrations

BMV examinations are implemented consistent with the requirements of Table 1 item B4.10 in ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6). Surface and volumetric examinations are implemented consistent with ASME Code Case Table 1, Item Number B4.20 for reactor vessel upper head components composed of Alloy 600/82/182 material. 10 CFR 50.55a(g)(6)(ii)(D) requires volumetric and/or surface examination of essentially 100% of the required volume or equivalent surfaces of the nozzle tube. Inspection frequency and susceptibility to crack initiation are determined by ASME Code Case N-729-1 Table 1 and section 2400.

Examination listed in Table 1, Item B4.30 and B4.40, of Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), will be performed for the new Alloy 690 nozzles as a baseline examination and subsequent examinations.

RPV BMI Nozzles, Unit 1 Pressurizer Instrument Nozzles, RCS Dissimilar Metal Welds, and RCS Piping Instrument Nozzles

BMV examinations for the following reactor coolant pressure boundary components are implemented consistent with noted items of Table 1 ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4).

- RPV BMI Nozzles – item B15.80
- Unit 1 Pressurizer Instrument Nozzles – item B15.180
- RCS Piping Instrument Nozzles – item B15.200 (Hot Leg) and B15.205 (Cold Leg)
- RCS Piping Dissimilar Metal Welds – item B15.215 (Cold Leg)

Note: Examination frequencies are identified in Element 5.

Monitoring and Trending – Element 5

The following examination frequencies are identified by the Nickel Alloy Aging Management Program for Alloy 600 locations. The examination frequencies are specified by the requirements noted in element 4. Examinations are for all units unless a unit specific examination is indicated.

a) Reactor Pressure Vessel (RPV) Upper Head Penetrations:

1) An Above Head Bare Metal Visual Examination of each RPVH every refueling outage
2) Under Head NDE Examination of each RPVH penetration every refueling outage.

~~Reactor Vessel Head replacements for all three PVNGS Units are scheduled from year 2009 to year 2010.~~ The original Unit 1 and Unit 3 reactor pressure vessel (RPV) heads are planned to be replaced during the refueling outages in 2010. The Unit 2 RPV head was replaced during 2R15 outage in Fall 2009.

b) Bottom Mounted Instrumentation (BMI) Nozzles:

1) Bare metal examinations of 100% of the nozzles every other refueling outage.

c) Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material:

1) Bare metal visual examinations of 100% of the instrument nozzles each refueling outage.

d) RCS Dissimilar Metal Butt-Welds:

(Note that the implementation schedule for each unit is defined in the Program Plan)

100% volumetric every 6 years and bare metal visual examination once every three (3) refuelings ~~s~~ outages when volumetric exams are not performed (MRP-139 Exam Category E):

- Safety Injection 1A
- Safety Injection 1B
- Safety Injection 2A
- Safety Injection 2B

Bare Metal visual examination once every three (3) refuelings (MRP-139 Exam Category K):

- PZR Spray 1A
- PZR Spray 1B
- Drain Line 1A
- Drain Line 1B
- Drain Line 2A
- Letdown Line
- Charging Line

e) RCS Piping Instrument Nozzles

1) Bare metal examinations of the 12 Cold Legs with SB-166 material nozzles once per ISI interval.

2) Bare metal examinations of the 8 RCP instrument taps nozzles once per ISI interval.

3) Bare metal examinations of the 8 Unit 2 Hot Leg pressure instrument nozzles every refueling outage.

Due to the repair/replace strategy implemented for indications/cracking, trending is not performed in the Palo Verde Nickel Alloy AMP.

RPV – Upper Head Penetrations

BMV, surface and volumetric examination frequencies for Reactor Vessel Upper Head Inspections are identified by the Nickel Alloy AMP for Alloy 600 locations and are consistent with ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6). ASME Code Case N-729-1 Table 1 Item Number B4.20 specifies volumetric and surface examinations be performed on all nozzles every 8 calendar years or before 2.25 reinspection years (for crack propagation) whichever is less for reactor vessel upper head components composed of Alloy 600/82/182 material. Inspection frequency and susceptibility to crack initiation will be determined by ASME Code Case N-729-1 Table 1 and section 2400.

RPV BMI Nozzles, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles

BMV examination frequencies for BMI penetrations, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles are consistent with ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4).

Acceptance Criteria – Element 6

Evaluations and acceptance criteria are in accordance with industry codes (e.g., ASME Code) or meet the acceptance of the NRC. For components included in EPRI ~~1010087~~ 1015009 (MRP-139), as listed in Palo Verde Alloy 600 Management Program Plan, it requires that all indications found during inspections must be evaluated per ASME Section XI requirements. Indications that do not satisfy IWB-3500 acceptance criteria must be dispositioned by analysis (such as IWB-3600), repaired or replaced.

RPV- Upper Head Penetrations

Relevant flaw indications detected as a result of Bare Metal Visual examinations are evaluated in accordance with acceptable flaw evaluation criteria provided in ASME Code Case N-729-1 section 3140. Relevant flaw indications detected as a result of volumetric and surface examinations are evaluated in accordance with acceptable flaw evaluation criteria provided in ASME Code Case N-729-1 section 3130. For Bare Metal Visual examinations, once ISI has concluded evidence of leakage is present, the examination is forwarded to engineering for evaluation and disposition.

Examinations listed in Table 1, Item B4.30 and B4.40, of Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), will be performed for the new Alloy 690 nozzles as a baseline examination and subsequent examinations.

RPV BMI Nozzles, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles

For Alloy 600 reactor coolant pressure boundary locations other than the RPV Upper Head, relevant flaw indications detected as a result of BMV examinations are evaluated in accordance with acceptable flaw evaluation criteria (IWB-3522) provided in ASME Code Case N-722, subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4). Indications that do not satisfy IWB-3500 acceptance criteria must be dispositioned by analysis (such as IWB-3600), repaired or replaced.

Corrective Actions – Element 7

Relevant indications failing to meet applicable acceptance criteria are repaired or evaluated in accordance with the plant corrective action program.

PVNGS site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B that are acceptable for addressing corrective actions.

Confirmation Process – Element 8

PVNGS QA procedures, review and approval processes and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B, which are acceptable in addressing confirmation processes.

Administrative Controls – Element 9

PVNGS QA procedures, review and approval processes and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B, which are acceptable in addressing administrative controls.

Operating Experience — Element 10

PVNGS has proactively replaced:

- all of the Alloy 600 pressurizer instrument nozzles (seven pressurizer nozzles in Unit 1 were welded using 82/182 weld material since the equivalent Alloy 690 weld material (52/152) was not commercially available at the time of the repair) and hot leg instrument nozzles in each Unit
- all pressurizer heater sleeves (36 per Unit)

- instrument nozzles in the steam generator cold leg plenum as part of the steam generator replacements on Units 1, 2 and 3.

A failure history, including repair or replacement information, search shows the following:

Component / Failure History / Repair or Replacements

a) Reactor Pressures Vessel (RPV)

- RPV Upper Head Penetrations / No CEDM indications. U2 vent line indications 2R12 / U2 RPV Upper Head replaced during U2R15. All penetrations of the new heads and welds, including the head vent, will be Alloy 690. ~~U2 vent line indications repaired by machining~~

- Bottom Mounted Instrument Nozzles (BMI) / No failures / None.

b) Pressurizer Nozzles

- Pressurizer instrument nozzles (7 each unit) / U1 1991 / Replaced with Alloy 690 material

- Pressurizer heater sleeves / Leaking nozzles, 6 circ and 6 axial indications (not leaking) / Preventively replaced all PZR sleeves in 3 units using external pad and partial nozzle replacement

c) Dissimilar Metal Welds

- PZR Spray / No Failures / FSWOL 3 Units

- PZR Safeties / No failures / FSWOL 3 Units

- Surge Line (HL and PZR Side) / No failures / FSWOL 3 Units

- PZR Spray 1A and 1B / No failures / None

- Shutdown Cooling 1 and 2 / No Failures / FSWOL 3 Units ~~(Unit 3 planned Spring 2009)~~

- Safety Injection lines / No failures / None

- Drain Line 1A and 1B / No failures / None

- Drain Line 2A / No failures / None

- Letdown Line / No failures / None

- Charging Line / No failures / None

d) RCS Piping Instrument Nozzles

- 27 Hot Legs (each unit) / 5 cracked nozzles, suspect PWSCC / Preventively replaced all 27 nozzles in 3 units using partial nozzle replacement with OD j-weld
- 12 Cold Legs (each unit) / No failures / None
- RCP instrument taps / No failures / None

NRC Bulletin 2003-02 - Lower Head Penetrations

In response to NRC Bulletin 2003-02, "*Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity*", PVNGS performed visual examinations during refueling outages U1-R12 - ending Dec. 2005, U2-R12 - ending May 2005, U3-R11 - ending Dec. 2004, U3-R12 - ending May 2006 of all 61 bottom mounted instrumentation (BMI) nozzles by a PVNGS Level III VT-2 qualified examiner. No boric acid deposits were noted in the area of the nozzle annulus during the "as-found" inspections. The 61 nozzles showed no evidence of leakage.

NRC Bulletin 2004-01 - Pressurizer Penetrations

In response to NRC Bulletin 2004-01, PVNGS performed pressurizer heater sleeve visual inspections and did not identify any leakage.

On June 7, 2004, PVNGS Unit 3 went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves. The inspection did not identify any leakage.

On June 14, 2004, all three PVNGS units went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves in all three units. The inspection did not identify any leakage.

On July 13, 2004, Unit 2 went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves. The inspection did not identify any leakage.

The pressurizer instrument nozzles in all three units have been replaced with Alloy 690 nozzles. Also, during the 11th refueling outage, from Sept. 2003 through Dec. 2003, for Unit 2, 34 of 36 pressurizer heater sleeves (Alloy 600) were replaced with thermally treated SB-167, Alloy 690, sleeves using the half-nozzle repair technique. The two sleeves that were not replaced were plugged during a previous outage using Alloy 690 material.

UNIT 1

In response to NRC Bulletin 2004-01 during Unit 1 refueling outage 12 ending December 2005, pressurizer bare metal visual inspections were performed and found no evidence of leakage. No relevant indications of through-wall leakage were identified during these inspections. No additional follow-up NDE was required. No relevant indications were observed. No boric acid residue was identified during the inspection of the pressurizer.

All 36 pressurizer heater sleeves were modified using the half-nozzle repair technique. The original heater sleeve was cut at a location within the pressurizer lower shell. A weld pad of Alloy 690 was overlaid on the exterior surface of the shell. New Alloy 690 sleeves were inserted and attached to the weld pad. This repair resulted in the relocation of the ASMEpressure boundary weld from the inside surface to the outside surface of the pressurizer shell. The repairs were made using Alloy 690 material.

UNIT 2

In response to NRC Bulletin 2004-01 during Unit 2 refueling outage ending May 2005, pressurizer bare metal visual inspections were performed and found no evidence of leakage. No relevant indications of through-wall leakage were identified during this inspection. No additional follow-up NDE was required. No boric acid residue was identified during the inspection of the Unit 2 pressurizer. No corrective actions were required.

UNIT 3

In response to NRC Bulletin 2004-01 during Unit 3 refueling outage 11 ending December 2004, PVNGS normally visually examines the pressurizer shell exposed by the gap between the insulation and the heater sleeves and other nozzles. However, during the heater sleeve modification project performed in Unit 3, the bottom shell insulation was removed and no corrosion was seen.

The Unit 3 pressurizer had three heater sleeves that were repaired during previous outages. These were repaired using a mechanical nozzle seal assembly (MNSA). There were no relevant indications of through-wall leakage during the inspection of the Unit 3 pressurizer heater sleeves including the 3 sleeves previously repaired. No additional follow-up NDE was required based on the initial eddy current results.

No boric acid residue was identified during the inspection of the Unit 3 pressurizer.

Although there was no visual evidence of boron leakage identified at the start of the outage, APS had previously decided to permanently modify the heater sleeves during 3R11. All 36 heater sleeves, including the three previously repaired using a MNSA, were modified using the half-nozzle repair technique. The original heater sleeve was cut at a location within the pressurizer lower shell. A weld pad of Alloy 690 was overlaid on the exterior surface of the shell. New Alloy 690 half sleeves were inserted and attached to the weld pad. This repair resulted in the relocation of the ASME Pressure boundary weld from the inside surface to the outside surface of the pressurizer shell. The repairs were made using Alloy 690 material.

For Unit 3, refueling outage 12, by letter dated June 15, 2006, the NRC staff notified APS that the staff had closed their efforts with regard to the review of APS' Bulletin 2004-01 responses for PVNGS Units 1, 2, and 3.

Enhancements

None.

Conclusion

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

B2.1.37 Fuse Holders

Program Description

The Fuse Holder program manages thermal fatigue, mechanical fatigue, vibration, chemical contamination and corrosion of the metallic portions of fuse holders to ensure that fuse holders within the scope of license renewal are capable of performing their intended function. The fuses within the scope of license renewal at PV are not frequently removed or replaced.

Fuse holder clamps are constructed of copper alloy and are spring-loaded clips that hold the fuse ferrules or blades in place. NUREG- CR-6763 (NUREG-1760), "Aging Assessment of Safety-Related Fuses Used in Low and Medium-Voltage Applications in Nuclear Power Plants," study determined that fuses are susceptible to aging degradation that can lead to failure, however, the occurrence is infrequent.

The fuse holders that perform a license renewal intended function located outside of active devices will be tested for deterioration of the metallic clamps by using thermography. The fuse testing will be performed at least once every ten years. The first test will be completed before the period of extended operation.

The acceptance criteria for thermography testing will be based on the temperature rise above the reference temperature. The reference temperature will be ambient temperatures or the baseline temperature data from the same type of connections being tested.

Corrective actions for conditions that are adverse to quality are performed in accordance with the corrective action program as part of the QA program. The corrective action process provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable.

The Fuse Holders program is a new program that will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Fuse Holders program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.E5, "Fuse Holders."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Operating experience has shown that loosening of fuse holders and corrosion of fuse clips are aging mechanisms that, if left unmanaged, can lead to a loss of electrical continuity function.

The Fuse Holders program is a new program; therefore, plant-specific operating experience to verify the effectiveness of the program is not available. Industry operating experience that forms the basis for these programs is included in the OE element of the corresponding NUREG-1801, *aging management program description.*

As additional Industry and applicable plant-specific operating experience become available, the operating experience will be evaluated and appropriately incorporated into the program. This ongoing review of operating experience will continue throughout the period of extended operation, and the results will be maintained on site. This process will confirm the effectiveness of this new license renewal aging management program by incorporating applicable OE and performing self assessments of the program.

Conclusion

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

B3 TLAA SUPPORT ACTIVITIES

B3.1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

Program Description

The calculated design lifetime cumulative usage factor U for fatigue is defined by Subparagraph NB 3222.4 of the Section III of the ASME Boiler and Pressure Vessel Code. An equivalent term I(t) is defined for valves in Paragraph NB 3552. The acceptance criterion for systems and components designed to these requirements is that U or I(t) not exceed 1.0. These terms, and current values estimated or calculated for monitoring purposes, are also rendered as CUF, usage factor, fatigue usage, fatigue usage factor, cumulative usage, or cumulative fatigue usage factor.

The Metal Fatigue of Reactor Coolant Pressure Boundary program uses cycle counting and usage factor tracking to ensure that actual plant experience remains bounded by design assumptions and calculations reflected in the PVNGS UFSAR.

The existing Metal Fatigue of Reactor Coolant Pressure Boundary program requires manual review of the Control Room Logs and Post Trip Reviews; and any event transients or trips are recorded and added to those previously determined. A simplified cycle-based cumulative usage factor (CUF) is calculated for the pressurizer spray nozzle in each unit. The existing program requires corrective actions if the recorded numbers of cycles exceed the limits stated by the UFSAR, or if the pressurizer spray nozzle CUF exceeds 0.65. This 0.65 CUF action limit for the spray nozzle, and the monitoring method for it, will be superseded by the enhanced PVNGS fatigue management program.

The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will use a computerized, EPRI-licensed software program, FatiguePro®, which manages cumulative fatigue damage in metal components of the reactor coolant pressure boundary and the Class 2 portions of the steam generators with a Class 1 analysis. The FatiguePro® program will track fatigue usage for each of the selected components by either (1) stress-based fatigue (SBF) calculations, using a Green's transfer function to calculate the fatigue effects of transient cycles based on indicated severity, (2) cycle-based fatigue (CBF) calculations, which count transient cycles and assign the maximum design basis stress range per event pair in order to calculate fatigue effects, or (3) a simple comparison of the number of occurrences of transient cycles to the number assumed for design. The locations in which fatigue effects are controlled by counting alone (method 3) are those with relatively low design fatigue usage values, and therefore, for which cycle counting will suffice to demonstrate design basis compliance.

The results of the above methods for cycle count and fatigue monitoring will be summarized and reviewed at least once per fuel cycle. This review will identify the need for any corrective actions, including any necessary revisions to the fatigue analyses.

The scope of the existing Metal Fatigue of Reactor Coolant Pressure Boundary program includes transient cycle counting that encompasses all of the PVNGS NUREG/CR-6260 locations. The usage factors calculated by the enhanced program for limiting NUREG/CR-6260 locations will include environmental effects of the reactor coolant environment as determined by NUREG/CR-6583 and NUREG/CR-5704.

The Metal Fatigue of Reactor Coolant Pressure Boundary program is implemented via procedure. The existing procedure provides guidelines and requirements for manual fatigue management.

The existing procedure will be enhanced to provide guidelines and requirements for tracking both transient cycle counts and fatigue usage of fatigue-sensitive, safety related components, using the FatiguePro® software, to maintain the fatigue usage of components within the cumulative usage factor limit of 1.0 established by Section III Subsection NB of the ASME Boiler and Pressure Vessel Code. The enhanced program will include tracking of cumulative usage, counting of transient cycles, manual recording of selected transients, and review of FatiguePro® data.

NUREG-1801 Consistency

The Metal Fatigue of Reactor Coolant Pressure Boundary program is an existing program that, following enhancement, will be consistent with NUREG 1801, Section X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary".

Exceptions to NUREG-1801

None

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Scope of Program, Element 1

The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include (1) additional Class 1 locations with high calculated cumulative usage factors, (2) Class 1 components for which transfer functions have been developed for stress-based monitoring, and (3) Class 2 portions of the steam generators with a Class 1 analysis and high calculated cumulative usage factors

Preventive Actions - Element 2, Acceptance Criteria – Element 6, and Corrective Actions – Element 7

The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced with additional cycle count and fatigue usage action limits, and with appropriate corrective actions to be invoked if a component approaches a cycle count action limit or a fatigue usage action limit. Action limits permit completion of corrective actions before the design limits are exceeded.

Cycle Count Action Limit and Corrective Actions

An action limit will require corrective action when the cycle count for any of the critical thermal and pressure transients is projected to reach the action limit defined in the program before the end of the next operating cycle. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions must be taken before the remaining number of allowable occurrences for any specified transient becomes less than 1.

If a cycle count action limit is reached, acceptable corrective actions include:

1) Review of fatigue usage calculations

a. To determine whether the transient in question contributes significantly to CUF.

b. To identify the components and analyses affected by the transient in question.

c. To ensure that the analytical bases of the leak-before-break (LBB) fatigue crack propagation analysis and of the high-energy line break (HELB) locations are maintained.

d. To ensure that the analytical bases of a fatigue crack growth and stability analysis in support of relief from ASME Section XI flaw removal and inspection requirements for hot leg small-bore half nozzle repairs are maintained.

2) Evaluation of remaining margins on CUF based on cycle-based or stress-based CUF calculations using the PVNGS fatigue management program software.

3) Redefinition of the specified number of cycles (e.g., by reducing specified numbers of cycles for other transients and using the margin to increase the allowed number of cycles for the transient that is approaching its specified number of cycles).

4) Redefinition of the transient to remove conservatism in predicting the range of pressure and temperature values for the transient.

Cumulative Fatigue Usage Action Limit and Corrective Actions

An action limit will require corrective action when calculated CUF (from cycle-based or stress-based monitoring) for any monitored location is projected to reach 1.0 within the next

2 or 3 operating cycles. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions must be taken while there is still sufficient margin to accommodate at least one occurrence of the worst-case design basis event (i.e., with the highest fatigue usage per event cycle).

If a CUF action limit is reached acceptable corrective actions include:

1) Determine whether the scope of the monitoring program must be enlarged to include additional affected reactor coolant pressure boundary locations. This determination will ensure that other locations do not approach design limits without an appropriate action.

2) Enhance fatigue monitoring to confirm continued conformance to the code limit.

3) Repair the component.

4) Replace the component.

5) Perform a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded.

6) Modify plant operating practices to reduce the fatigue usage accumulation rate.

7) Perform a flaw tolerance evaluation and impose component-specific inspections, under ASME Section XI Appendices A or C (or their successors) and obtain required approvals from the regulatory agency.

For PVNGS locations identified in NUREG/CR-6260, fatigue usage factor action limits will be based on accrued fatigue usage calculated with the F(en) environmental fatigue factors determined by NUREG/CR-5704 and NURGE/CR-6583 methods required for including effects of the reactor coolant environment.

Parameters Monitored or Inspected – Element 3 and Monitoring and Trending - Element 5

The scope of the Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced with a revised list of monitored plant transients that contribute to high usage factor, and with a revised list of monitored locations in Class 1 piping and vessels and in parts of the Class 2 steam generators that have a Class 1 analysis

Operating Experience

The methods of the FatiguePro® software, used by the Metal Fatigue of Reactor Coolant Pressure Boundary program, were developed by EPRI for the industry, in response to NRC concerns that early-life operating cycles at some units had caused fatigue usage factors to accumulate faster than anticipated in the design analyses. This fatigue management program was therefore designed to ensure that the code limit will not be exceeded in the remainder of the licensed life. The industry operating experience program reviews industry experience, including experience that may affect fatigue management, to ensure that applicable experience is evaluated and incorporated in plant analyses and procedures. Any necessary evaluations are conducted under the plant corrective action program.

The Metal Fatigue of Reactor Coolant Pressure Boundary program was implemented in response to industry experience that indicated that the design basis set of transients used for Class 1 analyses of the reactor coolant pressure boundary did not include some significant transients, and therefore might not be limiting for components affected by them. The program has remained responsive to both industry and plant-specific emerging issues and concerns. Examples:

Pressurizer surge and spray nozzle, hot leg surge nozzle, and surge line transients:

Flow stratification, boron concentration, and spray line and nozzle fatigue concerns prompted operation with continuous spray from initial startup in all three units. The thermal stratification concerns were later documented in NRC Bulletin 88-11. The pressurizer nozzle weld overlays are supported by fracture mechanics analyses and periodic inspections acceptable under ASME Section XI as the means to address aging in the overlaid welds. These locations are included in the PVNGS fatigue management program, and these nozzles now have full- structural ~~strength~~ weld overlays with reanalyses including the thermal stratification and insurge-outsurge effects.

Auxiliary spray line and tee and partial main spray line and main spray check valve replacement:

The concerns raised by NRC Bulletin 88-08 prompted a series of evaluations, eventually prompting replacement of the main spray line from and including the main spray check valve to the nozzle, and the auxiliary spray line and tee inboard of the auxiliary spray check valve.

Linear elastic fracture mechanics analysis (LEFM) of indications in the Unit 2 pressurizer support skirt forging weld:

An inservice inspection detected two indications in the Unit 2 pressurizer support skirt forging weld, near the lower vessel head, which were evaluated by an LEFM fatigue crack growth analysis.

Unit 1 shutdown cooling suction line 1A excessive vibration:

~~Brief~~ Flow-induced vibrations ~~excursions~~ of the Unit 1 shutdown cooling suction line 1A prompted extensive investigation of causal mechanisms; and remedial actions, including evaluation of possible fatigue effects on piping, appending a revised isolation valve code analysis and valve operator dynamic qualification to the analysis of record, and relocation of the line 1A inboard isolation valve for all three units.

CE Owner's Group initiative on surge line micro cracking:

Recent concerns with possible micro cracking in the surge line nozzles are being addressed by a Combustion Engineering Owner's Group initiative, in which PVNGS is participating.

The fatigue usage factors at locations affected by these events depend not only on these salient events, but on many others. Therefore, even if a cycle limit is approached, an examination of the usage factors at these critical locations which takes credit for the fact that cycles are not being accumulated as rapidly for other events as assumed by the analysis, will in most cases demonstrate that usage factors will remain below the allowable limit of 1.0.

Results of fatigue monitoring at PVNGS to date also indicate that in most cases the number of design transient events assumed by the original design analysis should be sufficient for the period of extended operation, and that the design basis fatigue cumulative usage factor limit of 1.0 should not be exceeded at the monitored locations for the period of extended operation. See Section 4.3, which also addresses possible exceptions.

Conclusion

The continued implementation of the Metal Fatigue of Reactor Coolant Pressure Boundary program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.