APS A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear Generating Station

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102-06134-JHH/GAM
February 19, 2010

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
Response to December 29, 2009, Request for Additional Information Regarding the Aging Management Program (AMP) Audit for the Review of the PVNGS License Renewal Application, and License Renewal Application Amendment No. 9

By letter dated December 29, 2009, the NRC issued a request for additional information (RAI) related to the PVNGS license renewal application (LRA). On February 4, 2010, Lisa Regner, NRC Project Manager for PVNGS license renewal, agreed to extend the RAI response due date to February 19, 2010. Enclosure 1 contains APS's response to the December 29, 2009, RAI. Enclosure 2 contains PVNGS LRA updates to reflect changes made as a result of the RAI responses.

In addition to LRA changes reflecting the RAI responses, Enclosure 2 contains updates to LRA Sections A1.13 and B2.1.13, and Commitment 15 in Table A4-1, to reflect the completion of a Fire Water System aging management program enhancement. Procedures have been enhanced so that the PVNGS Quality Assurance Program will apply to Fire Protection structures, systems, and components that are within the scope of license renewal that are also part of the boundary of the Water Reclamation Facility.

Commitments being revised by this letter are shown on the Table A4-1 mark-up pages 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 2/19/10
(date)

Sincerely,

DCM/RAS/GAM

Enclosures:

1. Response to December 29, 2009, Request for Additional Information Regarding the Aging Management Program (AMP) Audit for the Review of the PVNGS License Renewal Application

2. Palo Verde Nuclear Generating Station License Renewal Application Amendment No. 9

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
	G. A. Pick	NRC Region IV (electronic)

ENCLOSURE 1

Response to December 29, 2009, Request for Additional Information Regarding the Aging Management Program (AMP) Audit for the Review of the PVNGS License Renewal Application

NRC RAI B2.1.2-1

Background:

Element 5, "Monitoring and Trending" of the Water Chemistry Aging Management Program (AMP) in the Generic Aging Lessons Learned (GALL) Report, Section XI.M2, indicates that whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

Issue:

Palo Verde Nuclear Generating Station (PVNGS) license renewal application (LRA), Appendix B, Section B.2.1.2 indicates that the applicant's Water Chemistry Program will be consistent with the GALL Report, Section XI.M2, and does not take any exceptions. It was indicated in the applicant's basis document PVNGS-AMP-B2.1.2, Water Chemistry, in Section 3.5 on page 17, that the PVNGS Water Chemistry Program increases the sampling frequency when a monitoring instrument is out of service. It is not clear to the staff if PVNGS is increasing the sampling frequency to verify that corrective actions are effective.

Request:

Provide additional information clarifying if PVNGS increases the sampling frequency in order to verify the effectiveness of corrective actions used to address an abnormal condition. If PVNGS does not increase sampling frequency, provide additional information on how PVNGS plans to take an exception to the GALL Report, and what alternative technique will be used to address the effectiveness of corrective actions.

APS Response to RAI B2.1.2-1

Based on recent reviews Palo Verde has determined that specific procedural guidance for increased sampling due to abnormal chemistry conditions is appropriate to verify the effectiveness of corrective actions. PVNGS Systems Chemistry Specifications procedure 74DP-9CY04, Section 3.0 has been revised (Revision 67, effective December 23, 2009), as follows, to add guidance that will increase the sampling rate due to an abnormal chemistry condition:

> "If an Action Level is entered as described in this procedure, increase sampling to verify the effectiveness of corrective actions. Consider increasing the sampling rate due to an abnormal chemistry condition based on direction from Chemistry Management to ensure that corrective actions are effective. [Ref: Step 5.2.38]"

In addition, LRA Sections A1.2 and B2.1.2, and Commitment No. 4 in Table A4-1, have been revised to delete the purgeable organic carbon enhancement. PVNGS does not detect purgeable organic carbon (POC) and non-purgeable organic carbon (NPOC) from the effluent of new resin used in the secondary system. Instead, an alternate

analysis is being done that accomplishes the same result. This alternative analysis has been incorporated into the plant procedure that provides the specifications for bulk chemistry.

Also, LRA Sections A1.2 and B2.1.2 have been revised, as shown in LRA Amendment No. 9 in Enclosure 2, to delete "hardening and loss of strength" from the aging effects managed by the Water Chemistry program because this is not included in the GALL.

NRC RAI B2.1.3-01

Background:

GALL Report, AMP XI.M3, "Reactor Head Closure Studs," program Element 4, "detection of aging effects," states that "Examination category B-G-1 for pressure-retaining bolting greater than two inches diameter in reactor vessels specifies... surface and volumetric examination of studs when removed."

Issue:

Based on its review of the PVNGS Reactor Head Closure Studs program, the staff has determined that only volumetric examinations are provided for studs when removed from the reactor flange.

Request:

- Explain why this is not identified as an exception to the GALL Report's recommendations or identify it as an exception to the GALL Report; and
- Justify why volumetric examination (only) of reactor head closure studs when removed provides adequate detection of the aging effects for which the Reactor Head Closure Stud program is credited.

APS Response to RAI B2.1.3-01

In AMP XI.M3, Element 4, no exception is necessary; the volumetric examination of reactor head closure studs, when removed, meets ASME Section XI Code requirements. This conclusion is based on an inconsistency in the GALL with an incorrect quote from the ASME Section XI Code Table 2500-1.

The following passage of NUREG-1801 AMP XI.M3 program element 4 "Detection of Aging Effects" appears to be incorrect because ASME Section XI, Code Edition 2001, including the 2002 and 2003 addenda, allows surface <u>or</u> volumetric examination when closure studs are removed:

> "Components are examined and tested as specified in Table IWB-2500-1. Examination category B-G-1, for pressure-retaining bolting greater than 2 in. diameter in reactor vessels specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole, and surface and volumetric examination of studs when removed."

It appears that the phrase "surface and volumetric examination of studs when removed" should have been changed to "surface or volumetric examination of studs when removed" when the ASME code version cited in NUREG-1801 was changed. Since the PVNGS program is consistent with Table IWB-2500-1, examination category B-G-1 in ASME Code Edition 2001 including the 2002 and 2003 Addenda, the program is consistent with NUREG-1801.

NRC RAI B2.1.4-1

Background:

In the GALL Report AMP XI.M10 "Boric Acid Corrosion," covers any structures or components on which boric acid corrosion may occur. The scope of the program includes all components that contain borated water that are in proximity to structures and components that are subject to an aging management review (AMR).

Issue:

In Table 3.2.2-4 of the LRA, a line item for the heat exchanger (shutdown cooling) is indicated as carbon steel with stainless steel cladding in an environment of treated borated water. The applicant specifies that this line item is to be covered under the Water Chemistry Program for the aging effect of loss of material. The applicant further states that the Boric Acid Corrosion Control Program is consistent with GALL Report AMP XI.M10; however, the GALL Report recommends that AMP XI.M10 be applied to manage aging of the subject material/environment combination. It is not clear to the staff how the carbon steel heat exchanger component, clad with stainless steel, is managed sufficiently by the Water Chemistry Program rather than the Boric Acid Corrosion Control Program.

Request:

Provide additional information on how the applicant's AMP for managing the aging effects of the subject heat exchanger are consistent with the recommendations in the GALL Report.

APS Response to RAI B2.1.4-1

The aging management review of the Shutdown Cooling Heat Exchanger in LRA Table 3.2.2-4 is consistent with the GALL Report, and evaluates the environments

noted below for the channel cylinder, tubesheet, and shell subcomponents. The Shutdown Cooling Heat Exchanger tubesheet divides the two internal environments present in the channel cylinder and shell. The tubesheet and channel cylinder are constructed of carbon steel with stainless steel cladding.

Treated Borated Water Environment
(Internal – channel cylinder side of Shutdown Cooling Heat Exchanger)

Loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking of the stainless steel cladding of the Shutdown Cooling Heat Exchanger channel cylinder and tubesheet exposed to treated borated water are managed by AMP B2.1.2, Water Chemistry Program. Loss of material due to boric acid corrosion is not applicable to the channel cylinder and treated borated water side of the tubesheet since the subject material is stainless steel.

Closed-Cycle Cooling Water Environment – Internal
(Internal – shell side of Shutdown Cooling Heat Exchanger)

Loss of material due to pitting crevice and general corrosion of carbon steel of the Shutdown Cooling Heat Exchanger shell and tubesheet exposed to closed-cycle cooling water is managed by AMP B2.1.10, Closed-Cycle Cooling Water Program. Loss of material due to boric acid corrosion is also not applicable to the internal surfaces of the shell and Closed-Cycle Cooling Water side of the tubesheet since the environment is Closed-Cycle Cooling Water.

Borated Water Leakage Environment
(External surfaces of Shutdown Cooling Heat Exchanger channel cylinder)

Loss of material due to boric acid leakage of exterior carbon steel surfaces of the Shutdown Cooling Heat Exchanger channel cylinder exposed to an environment of borated water leakage will be managed by AMP B2.1.4, Boric Acid Corrosion Program.

LRA Table 3.2.2-4 (page 3.2-38) has been revised, as shown in Amendment No. 9 in Enclosure 2, to add loss of material of the Shutdown Cooling Heat Exchanger carbon steel exterior surfaces of the channel cylinder exposed to an environment of borated water leakage that is managed by AMP B2.1.4, Boric Acid Corrosion Program.

LRA Table 3.2.2-4 (pages 3.2-38 and 39) has also been revised, as shown in Amendment No. 9 in Enclosure 2, to change the standard note from "A" to "C" for the following aging management reviews:

- Loss of material of the stainless steel cladding of the Shutdown Cooling Heat Exchanger channel cylinder and tubesheet exposed to treated borated water managed by AMP B2.1.2, Water Chemistry Program.

- Cracking of the stainless steel cladding of the Shutdown Cooling Heat Exchanger channel cylinder and tubesheet exposed to treated borated water managed by AMP B2.1.2, Water Chemistry Program.

NRC RAI B2.1.7-01

Background:

In GALL AMP XI.M18 "Bolting Integrity," the "program description" and program elements 1, 3, 4, and 6 (scope of program, parameters monitored/inspected, detection of aging effects, and acceptance criteria) all include recommendations for aging management of structural bolting and indicate that structural bolting is within the scope of the program.

The applicant's description of PVNGS AMP B2.1.7 "Bolting Integrity," in the LRA does not include mention of structural bolting as being within the scope of the PVNGS Bolting Integrity program. However, the LRA also does not identify exceptions to elements of GALL AMP XI.M18, with regard to aging management of structural bolting.

Issue:

In its review of the applicant's Program Evaluation Document for AMP B2.1.7 and through discussions with the applicant, the staff determined that structural bolting is not included within the scope of AMP B2.1.7. The staff does not understand why aging management of structural bolting by other AMPs, in lieu of AMP B2.1.7, is not identified as an exception to program element of GALL AMP XI.M18.

Request:

- Explain why use of AMPs different from the Bolting Integrity program for aging management of structural bolting was not identified as an exception to GALL AMP XI.M18.

- Identify what PVNGS AMPs provide aging management for structural bolting.

- Provide justification that the AMP(s) used for aging management of structural bolting are suitable for managing the aging effects in structural bolting for which the GALL Report credits AMP XI.M18 and provide aging management equivalent to what is recommended in GALL AMP XI.M18.

APS Response to RAI B2.1.7-01

Request 1 Response

Although in GALL AMP XI.M18, Bolting Integrity, the program description and program elements 1, 3, and 6 (scope of program, parameters monitored/inspected, and acceptance criteria) all include recommendations for aging management of structural bolting, it is indicated in GALL AMP XI.M18, Element 4 that the structural bolts and fasteners are inspected by Structures Monitoring Program or equivalent.

Also, as recommended in GALL Chapter III, the aging management evaluation of the structural bolting in GALL lines III.B2-7, III.B2-10, III.B3-7, III.B4-7, III.B4-10, and III.B5-7, all credit AMP XI.S6, Structural Monitoring Program for management Loss of Material.

Therefore, the aging management of structural bolting using AMP XI.S6, Structural Monitoring Program, is consistent with GALL and was not identified as an exception.

Request 2 Response

As indicated above, XI.S6, Structural Monitoring Program, provides aging management for structural bolting, consistent with the recommendation of GALL aging evaluation lines in Chapter III. The aging management evaluations for structural bolting of various buildings are addressed in LRA tables in Section 3.5 for Component Types such as Structural Steel and Support Non-ASME, which include the components of bolted connections and anchorage.

Request 3 Response

In GALL AMP XI.M18, Bolting Integrity, the program description indicates that the program generally includes periodic inspection for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. It also indicates that the program includes preventive measures to preclude or minimize loss of preload and cracking. Except for the inspection for loss of preload, which PVNGS identifies as an exception to GALL AMP XI.M18, the use of XI.S6, Structural Monitoring Program, is justified to be suitable for managing these aging effects in structural bolting, and, therefore, provides the equivalent aging management program to that recommended in GALL AMP XI.M18.

The aging effect of cracking is avoided by control of the lubricant to prevent the contamination that may cause the aging effect of cracking.

For the aging effect of Loss of Material, XI.S6, Structural Monitoring Program, provides adequate aging management for structural bolting with visual inspection. Guidance of acceptance criteria and corrective action also meet the requirements equivalent to that recommended in GALL AMP XI.M18.

Although loss of preload is not one of the parameters included during the periodic inspection in XI.S6, Structural Monitoring Program, loss of preload of the structural bolting is managed by control of preload during installation or maintenance activities.

NRC RAI B2.1.7-02

Background:

In LRA Section B2.1.7, the exception to Element 3, "parameters monitored/ inspected" describes a discussion of bolt preload in EPRI NP-5769, Volume 2, Section 10, with regard to job inspection of torque. The exception goes on to say that torque values are provided in procedures, vendor instructions, design documents or specifications and include consideration of expected relaxations of the fasteners over the life of the joint and gasket stress in the application of pressure closure bolting.

Issue:

Although the information in the LRA suggests that the applicant manages loss of preload by control of design and maintenance activities, and not by inspection activities, the staff has determined that the LRA does not provide a clear description of the exception of program Bolting Integrity program Element 3.

Request:

- Provide a clear description of the exception to program Element 3, identifying the specific recommendation in Element 3 to which the exception applies and specifically what the PVNGS Bolting Integrity program does in lieu of the GALL Report's recommendations.

- Justify that PVNGS' actions taken in lieu of the actions recommended in the GALL Report are adequate to manage the aging effect(s) for which the GALL AMP is credited.

APS Response to RAI B2.1.7-02

Request 1 Response

In GALL AMP XI.M18, Bolting Integrity, program element 3, parameters monitored or inspected, the specific recommendation to which the exception applies is that bolting for safety-related pressure retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress.

In lieu of inspection of preload, the preload is managed at PVNGS by control of preload during installation or maintenance activities. Guidance of the torque values is provided in

plant procedures, if not provided by the vendor instructions, design documents or specifications. EPRI NP-5769, Volume 2, Section 10, suggests that inspection of preload is usually not necessary if the installation method has been carefully followed.

For clarification, the following sentence has been added at the beginning of the exception summary of LRA Section B2.1.7, as shown in LRA Amendment No. 9 in Enclosure 2:

> "Loss of preload is not a parameter of inspection for the PVNGS Bolting Integrity Program."

Request 2 Response

It is indicated in EPRI NP-5769, Vol. 2, Section 10, that torque inspection is non-conservative since for a given fastener tension more torque is required to restart the installed bolts. The techniques for measuring the amount of bolt tension in an assembled joint are both difficult and unreliable. Inspection of preload is usually not necessary if the installation method has been carefully followed.

Guidance of the torque values is provided in plant procedures for installation and maintenance activities in PVNGS, if not provided by the vendor instructions, design documents or specifications.

NRC RAI B2.1.7-03

Background:

GALL AMP XI.M18, "Bolting Integrity," program Element 2, "preventive actions," states that, "Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, and the additional recommendations of NUREG-1339, to prevent or mitigate degradation and failure of safety-related bolting." NUREG-1339 emphasizes a recommendation in EPRI NP-5769 against the use of molybdenum disulfide (MoS_2) as a thread lubricant for safety-related bolting because it may create conditions favorable for SCC when exposed to primary system water.

Issue:

During review of GALL AMP XI.M3, "Reactor Head Closure Studs," the staff learned that the thread lubricant used for the reactor head studs is Lubriko L1G615, which contains one percent molybdenum disulfide. Although reactor head studs are not within the scope of the Bolting Integrity program and GALL AMP XI.M3 does not include recommendations related specifically to molybdenum disulfide, the staff is concerned that thread lubricants containing molybdenum disulfide are used on reactor head studs and may be used in other bolting applications at PVNGS.

Request:

- Clarify whether thread lubricants containing molybdenum disulfide are used for bolting that is included within the scope of the Bolting Integrity program.

- If such lubricants are used for bolting that is included within the scope of the Bolting Integrity program, explain why this was not identified as an exception to the "preventive actions" program element in GALL AMP XI.M18, "Bolting Integrity."

- Explain how the aging effects of concern in NUREG-1339 will be managed during the period of extended operation for both GALL AMP XI.M3 and XI.M18.

APS Response to RAI B2.1.7-03

Request 1 Response

The review of the nuclear steam supply system (NSSS) and balance of plant (BOP) systems maintenance procedures and engineering observations in the field confirm that molybdenum disulfide (MoS_2) lubricant is not used for bolting within the scope of the Bolting Integrity Program. The common lubricant in all of these procedures is either FelPro-N-5000 or Pure Nickel Never-Seez, neither of which have any molybdenum disulfide ingredients. While the procedures do state "FelPro N-5000 or equivalent" or "Never-Seez or equivalent," field observations and discussions with maintenance and other engineering personnel confirm molybdenum disulfide has not been used as an equivalent. Typical equivalent lubricants are:

- NeoLube (graphite based)
- FelPro-N-5000 is substituted for Never Seez
- Never Seez is substituted for FelPro-N-5000
- Mineral Oil – for bearings with mineral oil lubrication

Request 2 Response

From the research performed as stated above, molybdenum disulfide lubricants are not used for the bolting in the Bolting Integrity Program.

Request 3 Response

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 preload control, selection of bolting material, use of lubricants/sealants consistent with EPRI good bolting practices, and performance of periodic inspections for indication of aging effects. The program is supplemented by Inservice Inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

PVNGS good bolting practices are established in accordance with plant procedures. These procedures include requirements for proper disassembling, inspecting, and assembling of connections with threaded fasteners. The general practices that are established in this program are consistent with EPRI NP-5067, "Good Bolting Practices, Volume 1 and Volume 2," and the recommendations delineated in NUREG-1339.

Although the procedures for ensuring bolting integrity do not directly reference EPRI reports NP-5769 and TR-104213 or NUREG-1339 as applicable source documents for these recommendations, these procedures do incorporate the action items to ensure the integrity of the subject bolting connections.

The following PVNGS aging management programs supplement the Bolting Integrity program for management of loss of preload, cracking, and loss of material:

(a) ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program (B2.1.1), provides the requirements for inservice inspection of ASME Class 1, 2, and 3 safety-related pressure retaining bolting.

(b) ASME Section XI, Subsection IWF program (B2.1.29), provides the requirements for inservice inspection of safety-related component support bolting.

(c) External Surfaces Monitoring Program (B2.1.20) provides the requirements for inspection of pressure retaining closure bolting within the scope of license renewal.

NRC RAI B2.1.9-1

Background:

Element 2, "Preventive Actions" of the Open-Cycle Cooling Water System Aging Management Program in the GALL Report, Section XI.M20, indicates that the system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments.

Issue:

In the PVNGS LRA, Appendix B, Section B.2.1.9 indicates that the applicant's Closed-Cycle Cooling Water Program will be consistent with the GALL Report, Section XI.M20. It was indicated in the applicant's basis document PVNGS AMP-B2.1.9, Closed-Cycle Cooling Water System, in Section 3.3 on page 13, that PVNGS does not take credit for coatings and linings to mitigate the effects of aging. However, from further discussion with the applicant it was identified that the piping systems are internally coated. Coating degradation could lead to a reduction in heat transfer or create crevices that lead to a more aggressive corrosion environment. It is not clear to the staff how

PVNGS has taken into consideration the aging of the pipe internal coating, which could affect the function of the system if the coating is degraded.

Request:

Provide additional information that accurately depicts the material arrangement of the open cycle cooling water system including linings or coatings. Provide additional information on how the coating system is managed for aging affects.

APS Response to RAI B2.1.9-1

The internal surfaces of portions of the Essential Spray Pond system piping and the internal surfaces of the channel heads of the essential cooling water, diesel turbocharger air after-cooler, diesel lube oil cooler and diesel jacket water heat exchangers are coated with an epoxy-like coating. These coatings are not credited by PVNGS for aging management of the underlying material. Open-Cycle Cooling Water System AMP basis document Element 2 has been revised to clarify the coating material arrangement of open-cycle cooling water system.

Visual inspection procedures for the internal surfaces of Open-Cycle Cooling Water piping and heat exchangers identify coating failure or degradation as evidenced by corrosion nodules, fresh rust stains, missing sections of coating, or disbonded coating (blistered or bulged). Visual inspection procedures for heat exchanger channel heads and tubesheets require identification tube blockage or fouling. Plant procedures specify acceptance criteria for inspections of tubesheets and internal surfaces. Open-Cycle Cooling Water System AMP basis document Elements 3, 4, 5, and 6 have been revised to identify applicable plant procedures and procedure sections and their inspection requirements for coating degradation and indications of heat exchanger tube fouling with coating degradation products.

NRC RAI B2.1.10-1

Background:

Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54.4(a) provides the regulations for what plant systems, structures, and components (SSCs) are within the scope of the license renewal process. These include items under 10 CFR 54.4(a)(2), which are all nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in safety-related SSCs included in the scope of the license renewal. The Program Description of the Closed-Cycle Cooling Water Aging Management Program in NUREG-1801, Revision 1, Section XI.M21 indicates that the program includes a) preventive measures to minimize corrosion and SCC and (b) testing and inspection to monitor the effects of corrosion and SCC on the intended function of the component.

Issue:

PVNGS LRA, Appendix B, Section B.2.1.10 indicates that the applicant's Closed-Cycle Cooling Water Program will be consistent with the NUREG-1801, Revision 1 Section XI.M21 with various exceptions. It was indicated in both the LRA B2.1.10 Program Description and the applicant's basis document PVNGS AMP-B2.1.10, Closed-Cycle Cooling Water System, in Section 2.1 on page 5, that the program will not conduct internal inspections or performance testing for components in scope of license renewal under 10 CFR 54.4(a)(2). It is not clear to the staff what the technical basis is for limiting the prescribed guidance in the GALL Report, based on how a component was scoped into the license renewal process.

Request:

Provide justification for limiting the internal inspections and performance testing on components based upon the criteria that was used to scope these components into the license renewal process.

APS Response to RAI B2.1.10-1

The criteria that were used to scope components into the license renewal process also identified the license renewal intended function, as listed in NEI 95-10, applicable to those components. NUREG-1801 XI.M21 states that "the closed-cycle cooling water (CCCW) system program relies on maintenance of system corrosion inhibitor concentrations within specified limits" and additionally provides guidance that "non-chemistry monitoring techniques such as testing and inspection in accordance with EPRI TR-107396 for CCCW systems provide one acceptable method" to evaluate program effectiveness. NUREG-1801 XI.M21 further states that "these measures will ensure that the intended functions of the CCCW system and components serviced by the CCCW system are not compromised by aging." For each component, the specific non-chemistry monitoring technique is selected from among those provided in EPRI TR-107396 to reflect the actual conditions of component type, configuration and license renewal intended functions to be managed.

SSCs with LR Functions Relating to Material Integrity

The aging of components exposed to closed cycle cooling water with license renewal intended functions related to material integrity, such as pressure boundary or leakage barrier, is managed by maintaining water chemistry conditions, the effectiveness of which is verified by the non-chemical monitoring technique of inspection as provided in TR-107396 Section 8, "Additional Monitoring Techniques."

SSCs with LR Functions Relating to Heat Transfer

The aging of components exposed to closed cycle cooling water with the license renewal intended function of heat transfer are managed by maintaining water chemistry

conditions, the effectiveness of which is additionally verified by the non-chemical monitoring techniques of nondestructive evaluation (NDE), heat transfer performance testing, or flow monitoring as provided in TR-107396 Section 8, "Additional Monitoring Techniques."

NRC RAI B2.1.10-2

Background:

The Preventative Actions indicate of the Closed-Cycle Cooling Water System AMP in the GALL Report, Section XI.M21, indicate that this program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC.

Issue:

In the LRA, Appendix B, Section B.2.1.10 indicates that the applicant's Closed-Cycle Cooling Water Program will be consistent with the GALL Report, Section XI.M21, with various exceptions. It was indicated in the applicant's basis document AMP-B2.1.10, Closed-Cycle Cooling Water System, in Section 3.2 on page 15, that PVNGS takes exception to an aluminum "window" in the essential cooling water system. This exception is to employ the GALL Report, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components for this particular part of the system. In addition, further discussion with the applicant indicated that the material may not be aluminum.

Request:

Provide additional information on the actual material of the "window." If the window is not aluminum, but a different material, provide additional information on what aging management program will be used. If the window is indeed aluminum, provide a technical basis why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to inspect the aluminum component.

APS Response to RAI B2.1.10-2

Review of plant information from the Site Work Management System (SWMS) equipment database and a controlled drawing confirms that the material of the "window" in the essential cooling water system is aluminum.

Aluminum owes its excellent corrosion resistance to the barrier oxide film that is bonded strongly to its surface and, if that if damaged, re-forms immediately in most environments. Corrosion of aluminum in the passive range is localized, usually manifested by random formation of pits. The pitting potential principle establishes the conditions under which

metals in the passive state are subject to corrosion by pitting. For aluminum, pitting corrosion is most commonly produced by halide ions, of which chloride (Cl -) is the most frequently encountered in service. Pitting of aluminum in halide solutions open to the air occurs because, in the presence of oxygen, the metal is readily polarized to its pitting potential. Generally, aluminum does not develop pitting in aerated solutions of most non-halide salts because its pitting potential in these solutions is considerably more noble (cathodic) than in halide solutions and it is not polarized to these potentials in normal service. [Source: CM Key to Metals, "Corrosion of Aluminum and Aluminum Alloys" www.keytometals.com/Article14.htm.]

The Closed-Cycle Cooling Water System program AMP B2.1.10 uses corrosion inhibitors for management of iron-based alloys and copper-based alloys but not aluminum. The Closed-Cycle Cooling Water System program AMP B2.1.10 establishes water chemistry controls that limit chloride ion concentration and total halide ion concentration to low levels such that rapid and aggressive loss of material and pitting is not anticipated. Visual inspection performed in accordance with Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP B2.1.22 for loss of material, cracking, pitting, discoloration, surface irregularities and other signs of distress will identify degradation deficiencies prior to the loss of intended function. If the results of the internal inspection indicate age-related degradation of components in excess of established acceptance criteria, the deficiencies will be resolved via the PVNGS corrective action program.

NRC RAI B2.1.10-3

Background:

The Parameters Monitored/Inspected element of the Closed-Cycle Cooling Water System AMP in the GALL Report, Section XI.M21, recommends managing the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component conditions.

Issue:

In the LRA, Appendix B, Section B.2.1.10 indicates that the applicant's Closed-Cycle Cooling Water Program will be consistent with GALL Report, Section XI.M21, with various exceptions.

- In Section 3.3 on page 20, the exception (exception g) is to conduct periodic monitoring and inspection for certain heat exchangers, which do not have a license renewal heat transfer function, but are included as a pressure boundary. It is not clear to the staff how water chemistry control alone will ensure adequate aging management, especially associated with loss of material.

- In Section 3.3 on page 19, the exception is to conduct visual or non-destructive examination inspections for ventilation cooling coils, which do not have license renewal heat transfer function, but are included as a pressure boundary. It is not clear to the staff how water chemistry control, preventative maintenance, and the performance testing will ensure the adequate aging management, especially associated with loss of material.

- In Section 3.3 on page 29, the exception is to conduct periodic monitoring and inspection for regular, periodic inspection and testing of Reactor Coolant Hot Leg Sample Cooler. It is not clear to the staff how water chemistry control with operator observation of component performance is adequate for aging management, especially associated with loss of material.

Request:

- Provide additional information describing why an inspection technique is not being utilized to monitor the aging affect of these heat exchangers with regard to loss of material, and how water chemistry control alone is adequate to managing the aging degradation.

- Clarify how the hot water chemistry control in combination with the preventative maintenance and performance testing will adequately managing the aging affects associated with the ventilation cooling coils.

- Provide additional information describing why an inspection technique is not being utilized to monitor the aging affect of the Reactor Coolant Hot Leg Sample Cooler and how water chemistry control alone is adequate to managing the aging degradation.

APS Response to RAI B2.1.10-3

Request 1 Response

Heat exchangers that do not have a license renewal heat transfer function but are evaluated as having a license renewal intended function of pressure boundary or leakage barrier include the auxiliary steam vent condenser, cooler for auxiliary steam radiation monitor, cooling coils for normal HVAC Units, steam generator hot leg, cold leg and downcomer blowdown sample coolers, pressurizer steam space and surge line sample coolers, and safety injection sample coolers. The effectiveness of water chemistry control measures of these heat exchangers is verified by visual inspection of the internal surfaces of selected components fabricated of similar materials and exposed to closed-cycle water using the same corrosion inhibitor program. Closed-Cycle Cooling Water System AMP basis document Elements 3, 4, and 5 have been revised to identify applicable plant procedures and procedure sections and their inspection requirements for the internal

surfaces of representative components to serve as leading indicators of the effectiveness of water chemistry measures.

LRA Section B2.1.10 has been revised to reflect the changes described above, as shown in LRA Amendment No. 9 in Enclosure 2.

Request 2 Response

The effectiveness of water chemistry control measures of ventilation cooling coils is verified by performance testing which may include, but not be limited to, cooling coil performance tests to verify that the required flow rates (air and water) are achieved. For specific ventilation cooling coils not subject to cooling coil performance tests, the tests performed on ventilation cooling coils fabricated of the same material and exposed to closed-cycle cooling water using the same corrosion inhibitor program will provide assurance of the effectiveness of the water chemistry corrosion inhibitor program. Ventilation cooling coils are not subject to visual inspection of their internal surfaces or to NDE because the internal diameter and geometry of the coils preclude effective internal inspection. NUREG-1801 XI.M21 states that "the closed-cycle cooling water (CCCW) system program relies on maintenance of system corrosion inhibitor concentrations within specified limits" and additionally provides guidance that "non-chemistry monitoring techniques such as testing and inspection in accordance with EPRI TR-107396 for CCCW systems provide one acceptable method" to evaluate program effectiveness. NUREG-1801 XI.M21 further states that "these measures will ensure that the intended functions of the CCCW system and components serviced by the CCCW system are not compromised by aging." Performance testing is one of the specific non-chemistry monitoring techniques provided in EPRI TR-107396. The performance tests are considered to be preventative maintenance to provide assurance that license renewal intended functions are maintained during the period of extended operation.

Request 3 Response

The design configuration of the reactor coolant hot leg sample cooler is a sealed unit not subject to opening for routine inspection or maintenance. The effectiveness of water chemistry control measures for this heat exchanger is verified by visual inspection of the internal surfaces of selected components fabricated of similar materials and exposed to closed-cycle water using the same corrosion inhibitor program. Closed-Cycle Cooling Water System AMP basis document Elements 3, 4, and 5 have been revised to identify applicable plant procedures and procedure sections and their inspection requirements for the internal surfaces of representative components to serve as leading indicators of the effectiveness of water chemistry measures and to delete the crediting of operator awareness of the need for unusual throttling of the cooling water flow to this sample cooler in order to obtain a sample of the required temperature or of the inability to obtain a sample of the required temperature as an indication of a reduction in heat transfer for the sample cooler.

LRA Section B2.1.10 has been revised to reflect the changes described above, as shown in LRA Amendment No. 9 in Enclosure 2.

NRC RAI B2.1.12-1

Background:

GALL AMP XI.M26, Element 3, "Parameters Monitored/Inspected" states:

> The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detection of any degradation of the fuel supply line.

GALL AMP XI.M26, Element 6, "Acceptance Criteria" states:

> No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump.

The AMP basis document for the Fire Protection program, AMP-B2.1.12, Revision 3, in Section 3.3, Parameters Monitored or Inspected, states:

> The fuel oil supply line is managed by the Fuel Oil Chemistry and External Surface Monitoring AMPs. The Fuel Oil Chemistry Program uses One-Time Inspection Program to verify the effectiveness of the chemistry program.

The AMP basis document for the Fire Protection program, AMP-B2.1.12, Revision 3, in Section 3.6, Acceptance Criteria, states:

> The Fuel Oil Chemistry Program uses One-Time Inspection Program to verify the effectiveness of the chemistry program, ensuring there is no loss of function due to aging of the fuel oil supply line.

Issue:

Procedure 14FT-0FP05, Revision 19, Monthly Diesel Driven Fire Pump Start and Run, which is referenced in the Fire Protection Program basis document, states in Appendix A to visually inspect the diesel fuel oil supply line for signs of degradation and references the source of the inspection as the LRA.

Request:

Please confirm which program is used for performing this inspection and identify where the acceptance criterion for the inspection is specified.

APS Response to RAI B2.1.12-1

The aging of internal surfaces of components exposed to fuel oil, which are associated with the diesel-driven fire pump including the fuel oil supply piping line, is managed by the Fuel Oil Chemistry AMP B2.1.14, the effectiveness of which is verified by the One Time Inspection Program AMP B2.1.16 consistent with NUREG-1801. The One Time Inspection Program basis document has been revised so that the fuel oil supply line of one diesel driven fire pump will be included in the sample of components to be inspected.

The aging of external surfaces of components associated with the diesel-driven fire pump is managed by the External Surfaces Monitoring Program AMP B2.1.20 consistent with NUREG-1801.

Additionally, plant procedures require demonstration of the diesel driven fire pump operability by starting and running each pump on a monthly basis consistent with NUREG-1801 XI.M26. This test verifies that the fuel oil day tank is above the minimum level and also detects degradation of the fuel oil supply line by visual inspection while the diesel-driven fire pump is in operation. The Fire Protection Program AMP basis document Elements 3, 4, and 5 have been revised to clarify the aging management programs applied to manage the aging of the diesel-driven fire pump.

NRC RAI B2.1.12-2

Background:

GALL AMP XI.M26, Element 4, "Detection of Aging Effects" states:

> Visual inspections of the halon/CO2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO2 fire suppression system before the loss of the component intended function.

Issue:

LRA Section B2.1.12 has taken an exception that the testing and inspection frequency is once every 18 months. By letter dated December 7, 2009, APS Amendment No. 3 to the LRA changed the testing and inspection frequency for dampers to once every 54 months.

Request:

Provide a technical justification for the 54-month testing and inspection interval.

APS Response to RAI B2.1.12-2

With exception of the 54-month destructive testing of the Electro-Thermal Links (ETLs) to functionally test the fire dampers, halon and CO_2 fire suppression systems are actuated manually and automatically with a simulated test signal on an 18-month interval. In addition, an air flow test is performed to assure no blockage in the headers and/or nozzles on an 18-month interval.

With respect to the 54-month destructive testing of the Electro-Thermal Links (ETLs), PVNGS has performed an engineering analysis, consistent with the methodology described within EPRI Technical Report 1006756 "Fire Protection Equipment Surveillance Optimization and Maintenance Guide 2003" to extend the frequency of the test so that the confidence of functionality obtained by successful completion of the test is aligned with reliability and logistical concerns of the test. The calculation indicates that a full functional test every six years of the dampers actuated by ETLs will maintain a 95% success rate assuming the same amount of failures as have occurred in the last 10 years and adjusting for uncertainty at the 99% level. The selection of a testing interval of 54 months, compared to the calculated value of 72 months for 95% success rate, provides an additional margin of protection.

The 18-month halon and CO_2 fire suppression systems inspection intervals were previously in the initial PVNGS Units 1 and 2 Operating Licenses (OL), Appendix A, Technical Specifications 3.7.11.3 and 3.7.11.6. The NRC approved the relocation of the fire protection technical specifications to the UFSAR in OL Amendments 14 and 8 for Units 1 and 2, respectively, dated April 8, 1987 (prior to the issuance of the Unit 3 OL), using the guidance in Generic Letter 86-10. Subsequently, following the creation of the licensee-controlled Technical Requirements Manual (TRM) when the improved standard Technical Specifications were implemented in August 1998 (OL Amendment No. 117 for all three Units), the fire protection technical specifications were added to the TRM. In accordance with PVNGS OL License Conditions, APS may make changes to the approved fire protection program without approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. The 18-month halon and CO_2 fire suppression system circuit actuation testing and damper functional testing (destructive testing of the ETLs) intervals in the TRM were changed from 18 months to 54 months in November 2009 in accordance with the license condition as evaluated and documented in a PVNGS internal License Document Change Request.

NRC RAI B2.1.16-1

Background:

In the GALL Report, AMP XI.M32, Element 10 "operating experience (OE)" states that this program applies to potential aging effects for which there are currently no OE

indicating the need for an AMP. Nevertheless, the elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

Issue:

The LRA states that a review of the PVNGS plant-specific OE associated with the inservice inspection (ISI) Program has not revealed any ISI adequacy issues. Although there is no plant-specific OE associated with the PVNGS American Society of Mechanical Engineers (ASME) Section XI ISI Program that revealed ISI adequacy issues, any OE resulting from maintenance activities should be included for systems and components that will be subjected to one-time inspection.

Request:

Provide a summary of OE resulting from observations of loss of material, cracking and loss of heat transfer resulting from maintenance and associated corrective action activities.

APS Response to RAI B2.1.16-1

During LRA development, the population of Palo Verde-specific OE (corrective action documents and work orders) from 1996 thru October 2009 was compiled. Various search strings were used to identify the OE related to aging effects and aging mechanisms. This resulted in a population of about 16,000 Palo Verde OE documents for engineering review in support of the LRA.

The 16,000 OE documents were reviewed to identify OE that related to Palo Verde Aging Management Programs, aging management, and scoping and screening. The results of the review did not identify any OE that related specifically to the One-Time Inspection XI.M32 AMP. The reviews did identify OE relatable to the Water Chemistry (WC), Fuel Oil (FO), and Lubrication Oil (LO) programs.

The WC, FO, and LO OE documents were reviewed again in the context of the One-Time Inspection program and it was determined that the OE did not identify any degradation of plant system piping and components associated with WC, FO, and LO programs that are in-scope of license renewal and managed by AMP B2.1.16, One-Time Inspection. The OE for WC, FO, and LO identified items, such as mechanical joint leakage, out of specification chemistry, bearing wear products, presence of water in oil, manufacturing defects, and construction flaws. The OE for WC, FO, and LO did not identify loss of material, cracking, and loss of heat transfer for components managed by the One-Time Inspection AMP.

Based on the above plant-specific OE reviews, the WC, FO, and LO programs are effective in managing plant piping and component aging effects. The One-Time

Inspection program will confirm the long-term effectiveness of the WC, FO, and LO programs in the ten year period prior to the period of extended operation.

NRC RAI B2.1.16-2

Background:

In the GALL Report, AMP XI.M32, Element 4 "detection of aging effects" recommends enhanced visual inspection (EVT-1 or equivalent) and/or volumetric inspection (RT or UT) for detection of cracking due to SCC or cyclic loading. In addition to enhanced visual inspection and/or volumetric inspection, the One-Time Inspection Program (B2.1.16) provides an option to use surface examination (PT or MT) to detect cracking.

Issue:

In the Nuclear Administrative and Technical Manual, One-Time Inspection Program (73DP-9EE05), it is stated that examination techniques will be selected as appropriate for each specific one-time inspection. It is not clear how surface examinations will be used to detect cracking.

Request:

Will surface examination be used instead of enhanced visual or volumetric inspection? If surface examination is to be used to detect SCC, will the examination be on the wetted surface of the component?

APS Response to RAI B2.1.16-2

The nondestructive examination (NDE) technique selected will examine the wetted surface of the material. If the wetted surface is not accessible for visual or surface examination, then a volumetric examination (e.g., UT, RT) will be conducted. The inspection methods listed in the Element 4 table are the applicable NDE techniques for use depending on component conditions and location of the surfaces being evaluated for aging effects.

The context of the PVNGS One-Time Inspection Program and the associated PVNGS procedure for one-time inspection is to identify aging effects associated with the material surfaces in contact with Water Chemistry (WC), Fuel Oil (FO), or Lubrication Oil (LO) environments. The NDE selected must be consistent with evaluating the material surfaces that are in contact with the applicable environment to identify any aging effects associated with the environment. For instance, the PVNGS procedure specifies inspection of internal pressure boundary surfaces for piping/tubing. The PVNGS procedure discusses removal of valve bonnets for internal valve inspections and also discusses internal inspections of open flanges, pipe, and tanks.

NRC RAI B2.1.18-1

Background:

The LRA states that AMP B.2.1.18, "Buried Piping and Tanks Inspection," is a new program with exceptions to elements 1, 2, and 6 of the GALL Report, AMP XI.M34. The description of AMP B.2.1.18 in the LRA includes a discussion of relevant plant-specific OE.

Issue:

There have been a number of recent industry events involving the leakage from buried piping (e.g., Oyster Creek Nuclear Generating Station, Indian Point Nuclear Generating Units 2 and 3, etc.) due to corrosion stemming from coating damage during backfill of piping, failure of fiberglass piping, and failure of buried piping in and around piping penetrations. Based on the information provided in the LRA, it is not clear to the staff how these and other examples of relevant industry operating experience was considered during the development of AMP B.2.1.18.

Request:

Please describe how relevant industry operating experience was considered during the development of AMP B.2.1.18.

APS Response to RAI B2.1.18-1

Industry operating experience was incorporated into the development of the PVNGS Buried Piping and Tanks Inspection AMP B.2.1.18 (XI.M34) by the review and inclusion of selected provisions of industry guideline documents and by direct participation of PVNGS personnel in industry forums on the subject.

The following industry operating experience references were used in the development of the PVNGS Buried Piping and Tanks Inspection AMP B.2.1.18 (XI.M34):

- NEI Technical Report 07-07, Nuclear Energy Institute, Industry Ground Water Protection Initiative, Final Guidance Document, August 2007.
- NUREG 1801, Program XI.M34, PVNGS Aging Management Program Evaluation Report Buried Piping and Tanks Inspection – B2.1.18, May 2009.
- EPRI Report 1016456, Recommendations for an Effective Program to Control the Degradation of Buried Pipe, December 2008.
- NEI, APC 09-03, Buried Piping Integrity Initiative, November 24, 2009.

PVNGS personnel were fully engaged with many others in the industry in the EPRI Buried Piping Integrity Group (BPIG) in learning from the recent events, including the operating experiences at Oyster Creek and Indian Point. The PVNGS Buried Piping and Tanks Inspection AMP B.2.1.18 (XI.M34) takes into account the lessons learned from these events and the developments after these events. Palo Verde is fully engaged and a key participant in the STARS Buried Piping Integrity Team as well as the NEI initiative on Buried Piping.

NRC RAI B2.1.19-1

Background:

GALL AMP XI.M35, Element 3, "parameters monitored/inspected," states that inspections will detect cracking in ASME Code Class 1 small-bore piping.

Issue:

The LRA states socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. The LRA further states that if a qualified volumetric examination procedure for socket welds endorsed by the industry and the U.S. Nuclear Regulatory Commission (NRC) is available and incorporated into the ASME Section XI at the time of PVNGS small-bore socket weld inspections then volumetric examinations will be conducted on small-bore socket welds. The staff notes that if a volumetric examination procedure for socket welds endorsed by the industry and the NRC is not available and incorporated into the ASME Section XI at the time of PVNGS small-bore socket weld inspections then present ASME Section XI Code requirements will be used for examination of socket welds. The staff also notes that the present ASME Section XI Code only requires surface examination for small-bore piping; however, surface examination will not detect cracking that initiates on the inside of the piping before leakage occurs.

Request:

If a volumetric examination procedure for socket welds endorsed by the industry and the NRC is not available and incorporated into the ASME Section XI at the time of PVNGS small-bore socket weld inspections, what alternative method will used to detect cracking that initiates from the inside of socket welds?

APS Response to RAI B2.1.19-1

If no volumetric examination procedure for ASME Code Class 1 small bore socket welds has been endorsed by the industry and the NRC and incorporated into ASME Section XI at the time PVNGS performs inspections of socket welded ASME Class 1 small-bore

piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

LRA Sections A1.19 and B2.1.19 have been revised, as shown in Amendment No. 9 in Enclosure 2, to include the use of a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds in the event a volumetric examination procedure endorsed by the industry and the NRC and incorporated into ASME Section XI is not available.

NRC RAI B2.1.19-2

Background:

In the GALL Report, AMP XI.M35, Element 1, "scope of program," recommends using guidelines in EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP24)," January 2001, to identify piping susceptible to potential effects of thermal stratification or turbulent penetration. The LRA states that guidelines from EPRI TR-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Revision B-A, were used for identifying susceptible piping instead of EPRI Report 1000701. The LRA further states that the recommended inspection volumes for both methods are identical.

Issue:

Although the inspection volumes are identical, it is not clear if the welds with the highest likelihood of degradation will be inspected, e.g., welds with the highest stress but not necessarily highest risk category.

The staff reviewed the applicant's selection of welds that would be subjected to volumetric one-time inspection based on the risk-informed method and found that only butt welds would be inspected. The staff noted that although the butt welds to be inspected have the highest risk, the environment of butt welds is not the same as for socket welds due to the crevice inherent in socket welds; the crevice could lead to corrosion or SCC in socket welds which could be missed if only butt welds are inspected.

Request:

Are locations that are to be inspected according to risk-informed methods also bound by the locations of the highest likelihood of degradation? Provide plans to augment the risk-informed selection of locations of small-bore piping for volumetric inspection to include socket welds.

APS Response to RAI B2.1.19-2

The risk-informed methodology used to categorize welds at PVNGS is based on the following two elements:

- Identifying and evaluating the degradation mechanisms for failure.
- Evaluating the consequences of a failure.

EPRI TR-112657, Revised Risk-Informed Inservice Inspection Evaluation Procedure, divides the potential for pipe rupture into three categories based on the degradation mechanism. The only degradation mechanism associated with the highest potential for failure is flow accelerated corrosion. All other degradation mechanisms are classified as medium potential for failure. The potential for failure is low if there is no degradation mechanism.

At PVNGS, no Class 1 piping is susceptible to flow accelerated corrosion. All the Class 1 welds, therefore, have either medium or low probability of failure. Some of the welds to be inspected fall into the medium probability category. Thus, the locations to be inspected are bound by the locations of the highest likelihood of degradation.

Class 1 socket welds at PVNGS are in the category of low probability of failure and are not included in the risk-informed sample population for volumetric inspection. PVNGS will augment the inspection population to include at least 1 socket weld in each unit. A different socket weld location will be selected for each unit.

LRA Sections A1.19 and B2.1.19 have been revised, as shown in Amendment 9 in Enclosure 2, to include a volumetric inspection of at least 1 socket weld in each unit with a different socket weld location selected for each unit.

NRC RAI B2.1.19-3

Background:

The LRA small bore piping AMP states that the program is consistent with the program elements in the GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping." It also states that PVNGS has experienced cracking of ASME Code Class 1 small-bore piping.

Issue:

Based on GALL Report Section XI.M35 recommendation, periodic inspection of the subject piping is needed as managed by a plant-specific AMP.

Request:

Either provide a plant-specific AMP that includes periodic inspections to manage aging, or provide justification why a plant-specific AMP is not necessary for ASME Code Class 1 small-bore piping.

APS Response to RAI B2.1.19-3

GALL Report AMP XI.M35 states "This program is applicable only to plants that have not experienced cracking of ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading. Should evidence of significant aging be revealed by a one-time inspection or previous operating experience, periodic inspection will be proposed, as managed by a plant-specific AMP."

PVNGS has experienced three instances where failures have occurred in ASME Code Class 1 small-bore piping with socket welds. The failures were reported in the following Licensee Event Reports (LERs):

- Unit 1 LER 87-018-00 for a socket weld on the upstream side of the isolation valve for the flanged refueling water level indication (NRC Agencywide Document Access and Management System [ADAMS] Accession No. 8803080078; APS letter no. 192-00342, February 19, 1988).

- Unit 1 LER 96-006-00 for a cracked weld in the minimum flow recirculation line for the Train B High Pressure Safety Injection pump (ADAMS Accession No. 9612040143; APS letter no. 192-00983, November 26, 1996).

- Unit 1 LER 2004-001-00 for a cracked socket weld on a high pressure safety injection line (ADAMS Accession No. ML041040027; APS letter no. 192-01135, April 4, 2004.)

Evaluations were performed to determine the cause of each of the failures. In each case, the failure was determined not to be cracking due to stress corrosion or thermal and mechanical loading. Since cracking due to stress corrosion or thermal and mechanical loading was determined not to be the cause, a plant-specific AMP is not necessary.

NRC RAI B2.1.20-1

Background:

GALL Report, AMP XI.M36, "External Surfaces Monitoring," includes a provision for inspecting areas that are inaccessible under normal operating conditions. AMP XI.M36 states that surfaces that are inaccessible or not readily visible during plant operations are inspected during refueling outages. Surfaces that are inaccessible or not readily visible

during both plant operations and refueling outages are inspected at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation.

Issue:

The applicant has indicated in its basis document, PVNGS AMP Evaluation Report External Monitoring Program – B2.1.20, that it plans to manage the aging effects of the elastomers by using physical manipulations to detect hardening and loss of strength of elastomers rather than visual inspection. The applicant has indicated that the physical manipulations are not possible for all instances as there are inaccessible regions that preclude any inspection techniques beyond visual inspection. This potentially leaves certain elastomeric components insufficiently assessed in the inspection process as their respective degradation can not be assessed solely by visual means.

Request:

Provide details on what alternative method will be used to adequately manage those elastomeric products not accessible for physical manipulation so that loss of ductility and aging artifacts specific to elastomeric materials will be detected. If the management of inaccessible components will involve sampling or inspection of equivalent or analogous component/materials/environments, then provide details on how those results will be applied to the elastomeric materials not accessible for physical manipulation.

APS Response to RAI B2.1.20-1

A review of elastomeric components within scope of license renewal did not identify any specific elastomeric components that are expected to be inaccessible for visual inspection. The External Surfaces Monitoring Program AMP basis document states that visual inspections are the primary program method for detecting loss of material due to external corrosion or material aging degradation, such as discoloration, checkering, and cracking of elastomers resulting from hardening or loss of strength. Physical manipulation during the visual inspection can also be used to verify the absence of hardening or loss of strength for elastomers. Plant procedures provide that supplemental examinations and engineering evaluations are used as a means for ensuring that the component's intended function will be performed through the next inspection cycle.

NRC RAI B2.1.20-2

Background:

GALL AMP XI.M36 is based on managing aging effects of steel through visual inspections. Based on the observable degradation artifacts intrinsic to steel, the GALL

AMP states that "visual inspections are expected to identify loss of material due to general corrosion in accessible steel components. Loss of material due to pitting and crevice corrosion may not be detectable through these same visual inspections, however, general corrosion is expected to be present and detectable such that, should pitting and crevice corrosion exist, general corrosion will manifest itself as visible rust or rust byproducts (e.g., discoloration or coating degradation) and be detectable prior to any loss of intended function."

Issue:

Within the LRA, the applicant has presented an exception to GALL AMP XI.M36 with the use of the AMP to cover other materials (aluminum, copper alloy, and elastomers). However, the sufficiency of visual inspection for observing steel degradation is founded on the color change upon degradation and, under with more advanced degradation, disengagement of corrosion products from the metal surface. Compared to steel, aluminum is not as conducive to visual inspection to detect degradation. Under the pertinent plant environments and conditions, the degradation of aluminum involves the formation of thin films of Al_2O_3 indistinguishable from its presence in the initial service condition. Until the degradation is so extensive that component functionality is compromised, the extent of corrosion is not conducive to detection by the visual inspection methods used for steel.

Request:

Explain how visual inspection can be applied to assess corrosion on aluminum components, specifically the loss of material. Provide details if other contact methods or optical instruments are intended for use in the inspection.

APS Response to RAI B2.1.20-2

In the mild environment to which aluminum components are exposed at PVNGS, rapid and aggressive corrosion of aluminum is not anticipated, and visual inspection for loss of material and general corrosion, degraded material or physical conditions, and chipping, cracking, flaking, oxidizing, or missing paint and coatings as defined in plant procedures will identify degradation deficiencies prior to the loss of intended function. Plant procedures require that degradation deficiencies are documented and evaluated by the System Engineer. The corrective action process will assure proper evaluation in accordance with standards and/or site specific methods, including the codes and standards consistent with the PVNGS CLB.

The External Surfaces Monitoring Program AMP basis document states that the program manages the aging of the external surfaces that are not subject to management by the Boric Acid Corrosion AMP or the Buried Piping and Tanks AMP. Such components are exposed to plant indoor air or atmosphere/weather environments. The characteristics of these environments are presented in LRA Table 3.0-1, and provided below:

Plant Indoor Air

The environment to which the internal and external surface of the component is exposed. Indoor air on systems with temperatures higher than the dew point, i.e., condensation can occur but only rarely, equipment surfaces are normally dry. Condensation on the surfaces of systems with temperatures below the dew point is considered raw water due to the potential for surface contamination.

Atmosphere/Weather

The atmosphere/weather environment consists of moist, ambient temperatures, humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions. Temperature extremes range from 11°F to 121°F. There is no exposure to salt spray or other aggressive contaminants.

Aluminum owes its excellent corrosion resistance to the barrier oxide film that is bonded strongly to its surface and, that if damaged, re-forms immediately in most environments. If destructive forces are absent, as in dry air, the natural film will consist only of the barrier layer and will form rapidly to the limiting thickness. Corrosion of aluminum in the passive range is localized, usually manifested by random formation of pits. The pitting potential principle establishes the conditions under which metals in the passive state are subject to corrosion by pitting. For aluminum, pitting corrosion is most commonly produced by halide ions, of which chloride (Cl -) is the most frequently encountered in service. Based on Palo Verde external environments component degradation so extensive that component intended function is compromised is not expected at Palo Verde. Therefore, visual inspection for loss of material due to pitting is used to identify aging of aluminum. components.

Pitting of aluminum in halide solutions open to the air occurs because, in the presence of oxygen, the metal is readily polarized to its pitting potential. Generally, aluminum does not develop pitting in aerated solutions of most non-halide salts because its pitting potential in these solutions is considerably more noble (cathodic) than in halide solutions and it is not polarized to these potentials in normal service. [Source: CM Key to Metals, "Corrosion of Aluminum and Aluminum Alloys" www.keytometals.com/Article14.htm.]

NRC RAI B2.1.20-3

Background:

The GALL Report recommends the Compressed Air Monitoring AMP XI.M24 for managing the aging of components in the compressed air system exposed to condensation.

Issue:

The applicant has claimed that their compressed air system does not include components/materials that are subjected to an environment of potential condensation. The piping and valves included within LRA Table 3.3.2-9 indicate that the applicant identifies no aging effects due to condensation that require management. However, further discussions with the applicant indicated that there are piping and valves in the plant compressed air system that are subject to potential condensation from indoor plant air.

Request:

The applicant is asked to clarify how the aging effects on piping and valves within the compressed air exposed to condensation will be managed for loss of material and other potential aging effects.

APS Response to RAI B2.1.20-3

Several components within the compressed air system were incorrectly identified as having an internal environment of dry gas. The internal environment has been changed to wetted gas for all components, with the exception of the components that supply nitrogen to the spent fuel pool gate seals. These components have an internal environment of dry gas. Loss of material for components with an internal environment of wetted gas within the compressed air system will be managed by AMP B2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."

LRA Section 3.3.2.1.9, and Tables 3.3.1 and 3.3.2-9, have been revised to reflect the changes described above, as shown in LRA Amendment No. 9 in Enclosure 2.

NRC RAI B2.1.22-1

Background:

The GALL Report says that indications of various corrosion mechanisms or fouling that would impact component intended function are reported and will require further evaluation. The acceptance criteria are established in the maintenance and surveillance procedures or other established plant procedures. If the results are not acceptable, the corrective action program is implemented to assess the material condition and determine whether the component's intended function is affected.

Section B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, includes in its scope fire water system piping to perform visual inspections that are capable of evaluating wall thickness and the inner diameter of the piping as it applies to the design flow of the fire protection system.

Issue:

The information provided in the LRA Section B2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, does not provide a specific method for determining the wall thickness of this fire protection piping and does not provide a specific method for determining indications of narrowing of the pipe diameter.

Request:

Describe how the wall thickness and narrowing of the pipe diameter will be determined by visual inspection and provide acceptance criteria.

APS Response to RAI B2.1.22-1

This response clarifies how the wall thickness and narrowing of the pipe diameter of fire protection piping will be determined by visual inspection and describes acceptance criteria.

Palo Verde will use accepted industry practices in place at the time of implementation of the program. These practices include but are not limited to our current method of verification, which is a visual inspection, looking for any evidence of degradation (i.e., pitting, corrosion, erosion, etc.). When visual inspection identifies evidence of a pipe wall thickness degradation, ultrasonic examinations are utilized to verify the remaining wall thickness is acceptable for continued operation.

The acceptance criteria is per standard ASME/ANSI specifications, or Engineering design minimum wall calculations. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program AMP basis document Element 6 has been revised to clarify the methods to be used to quantify wall thinning when visual inspections identifies evidence that such thinning may be occurring and to clarify how acceptance criteria will be established.

NRC RAI B2.1.23-1

Background:

In the GALL Report, AMP XI.39 recommends in Element 6, acceptance criteria, that particle concentration will be determined in accordance with industry standards such as SAE749D, ISO 4406, ISO 112218, and NAS 1638. Water and particle concentration will not exceed limits based on manufacturer's recommendations or industry standards recommended for each component type. Viscosity bands are based on a tolerance around the base viscosity of the lubricating oil as recommended by the component manufacturer or industry standards. Metal limits as determined by spectral analysis and

ferrography will be based on original baseline data and manufacturer's recommendations, industry standards, or other justified basis.

Issue:

The applicant stated in Lubricant Evaluations, Revision 12, 37DP-9MP04, that exceeding testing criteria of Appendix A is not necessarily the point where lubricating oil is non-conforming. The sources of acceptance criteria are not identified. Lubricant Evaluations, Revision 12, 37DP-9MP04, allows use of lubrication oil with parameters outside the limits of acceptance criteria based on a justification for doing so and a sampling interval is such that the condition of the oil is adequately monitored.

Request:

Provide sources of the acceptance criteria. Provide justification for continued use of lubricating oil outside manufacturer's recommendations or industry standards.

APS Response to RAI B2.1.23-1

Plant procedures provide guidance to the lubrication engineer in developing specific acceptance criteria for the continued use of lubrication oils. Reference sources used to develop the acceptance criteria are listed below.

- Booser, E. Richard, PhD, CRC Handbook of Lubrication, Volumes I &II, CRC Press, Inc., 1983.
- EPRI Report No. NP-4916, Lubrication Guide, January 1987.
- EPRI Report No. CS-4555, Guidelines for Maintaining Steam Turbine Lubrication Systems, July 1986.
- O'Conner, James J. and Boyd, John, Standard Handbook of Lubrication Engineering, McGraw hill Book Co., 1968.
- Lubricants Guide, Shell Oil Company, 1981.
- Chevron Research Bulletin, Copyright 1979 – Identified by numeral GHA-4-79-1.
- Cooper-Bessemer Model KSV Emergency Diesel Generator Lubricating Oil and Jacket Water Analysis Guidelines, revision #1 (October 1993).
- NAS 1638 Hyd Fluid Cleanliness.
- ASTM D 4378, Standard Practice for In-Service Monitoring of Mineral Turbine Oils for Steam and Gas Turbines.
- ASTM D 6224, Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment.

Engineering evaluations consider the data and use applicable reference sources in providing justification for continued use of lubricants that are outside of the stated procedure criteria. Per the station procedure, these evaluations can only be made by a Lubrication Engineer. This task/function is controlled through the station training program with a unique Job Qualification Card (JQC) for "Lubrication Engineer." Oils from quality or

quality-augmented machinery that are evaluated also have an Independent Verification (IV) performed. Lubricating Oil Analysis Program AMP basis document Element 6 has been revised to identify the sources used to establish acceptance criteria and to clarify the method by which continued use of lubricating oil outside manufacturer's recommendations or industry standards is allowed.

NRC RAI B2.1.23-2

Background:

In the GALL Report, AMP XI.M39, Element 3, "parameters monitored/inspected," recommends monitoring the Neutralization Number in lubricating oils.

Issue:

In the AMP B.2.1.23, Evaluation Report for Lubricating Oil Analysis, the applicant stated that diesel engine lubricating oil is tested for the Total Base Number but not the Total Acid Number, because the Total Acid number is of limited use for diesel engine lubrication oil applications; additionally, it is stated that the Total Acid Number is used for evaluating lubrication oils in other components. It is not clear why only the Total Base Number is used for monitoring lubricating oil in diesel engines and what lubricating oil of other components will be monitored for Total Acid Number.

Request:

Provide justification for only monitoring the Total Base Number for lubricating oil in diesel engines. Provide information regarding where the Neutralization Number, the Total Acid Number and the Total Base Number is used for monitoring lubricating oil in other components.

APS Response to RAI B2.1.23-2

The term 'Neutralization' is a higher tier term that could generically describe either Total Acid or Total Base Number measurements. Total Base and Total Acid Number tests are titrations which are used to determine a point of neutralization. In the case of Total Base Number, a measured amount of an acid is added to the oil sample which provides a measure of the base (Total Base Number) within the oil. In the case of Total Acid Number, a measured amount of a base material is added to the oil sample to obtain a measure of the weak acids that are in the oil.

Diesel oils are designed with a base additive. This is done as the combustion process within an engine can create acids which the oil design accounts for. Base Number testing is therefore only performed on diesel oils. In contrast to diesel oil formulation, the other oils tested at Palo Verde do not have the base additive as part of their formulation. An

example of this type of oil is turbine oil. These oils create weak acids as they degrade. The acid number test measures this chemical change for monitoring purposes and is the neutralization test used for these oils.

NRC RAI B2.1.23-3

Background:

In the GALL Report, AMP XI.39 recommends in Element 6, acceptance criteria, that particle concentration will be determined in accordance with industry standards such as SAE749D, ISO 4406, ISO 112218, and NAS 1638.

Issue:

The applicant stated in the AMP basis document, Lubricating Oil Analysis, B2.1.23, that the Lubricating Oil Analysis Program relies upon elemental analysis as described in ASTM D 6595, "Determination of Wear Metals and Contaminants in Used Lubricating Oils or Used Hydraulic Fluids by Rotating Disc Electrode Atomic Emissions Spectroscopy," to determine wear metal content in lieu of particle counting to characterize lubricating oil cleanliness in diesel engine applications. The applicant further stated that elemental analysis provides a greater degree of insight into lubricant condition over particle counting. The staff reviewed ASTM D 6595 and Lubricant Evaluations, Revision 12, 37DP-9MP04 and found no acceptance criteria for elemental analysis.

Request:

Provide the acceptance criteria for elemental wear metals in lubricating oil. Provide information indicating that elemental analysis provides a greater degree of insight into lubricant condition over particle counting.

APS Response to RAI B2.1.23-3

Acceptance Criteria for Elemental Analysis

ASTM D6595 does not provide rigidly defined acceptance criteria; rather it is used to ensure data precision and accuracy. The process used to determine machine acceptability is based upon trend analysis.

Test data measurements are statistically reviewed for potential wear issues based upon the distribution of data for that and similar monitored machines and also for the rate of change in the data. If either analysis technique indicates a potential data outlier, additional lab testing and investigation is performed. Then, as appropriate, a site process such as the corrective action program or operability determination is used to evaluate the condition.

Use of Elemental Analysis in lieu of Particle Counting

Particle Counting for cleanliness using the NAS 1638 standard is routinely performed on turbine oils at the station and is a standard industry test. Particle Counting for cleanliness measures particles to include wear metals, water droplets, fibers and air bubbles. This test does not discriminate between these particle types. Spectrometer testing (elemental analysis) for particles has a similarity to Particle Counting testing for cleanliness in that it measures the most common particles (units of measure in micron) with the smallest particles being the most common.

The spectrometer measures particles less than 10 micron in size. The particles measured include soluble and wear metals. The soluble metals are an indication of additives within the oil chemistry which can be related to expected oil performance. This information is not available through an NAS 1638 Particle Count.

The spectrometer counts 19 different metals. Many different metals or alloys are used within machinery. When wear occurs, the spectrometer measurements provide insight concerning the likely source and severity of the wear condition. For example, copper, tin and iron are among the metals uniquely counted. When no metals are measured with this test method, this is a clear indication of acceptable system or machine performance. As the spectrometer is able to discriminate between oil chemistries for soluble metals and measure individual metal types when wear does occur, it is well suited to provide additional insight beyond that possible with a Particle Counter for cleanliness as it provides information into both the lubricant and the machine condition.

NRC RAI B2.1.24-1

Background:

The GALL Report, XI.E1, Scope of Program, states that this inspection program applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments. Non-EQ electrical containment penetrations may be installed in adverse localized environments.

Issue:

The scope of program in the LRA, B2.1.24, does not include electrical containment penetrations.

Request:

Explain why electrical containment penetrations are not included in the scope of Electrical Cables and Connections.

APS Response to RAI B2.1.24-1

LRA Table 3.6.1 shows the Penetrations Electrical line being managed using aging management program Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B2.1.24).

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B2.1.24) aging management program was revised to clarify that the non-EQ electrical containment penetrations are included in the program. LRA Section B2.1.24 has been revised to include the following clarification, as shown in LRA Amendment No. 9 in Enclosure 2:

> "Connection insulation material includes termination kits and tape used to insulate splices that are normally located within junction boxes, terminal blocks located within terminal boxes, and non-EQ electrical containment penetrations."

NRC RAI B2.1.25-1

Background:

The GALL Report, XI.E2, Scope of Program, states that this program applies to electrical cables and connections (cable system) used in circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation that are subject to AMR. The LRA, AMP B2.1.25, under the same program attribute, only includes the ex-core neutron monitoring system cable system (nuclear instrumentation).

Issue:

The scope of AMP B2.1.25 does not include high range radiation monitoring.

Request:

Explain how the scope of the PVNGS AMP is consistent with the GALL Report, XI.E2, considering the fact that the PVNGS AMP does not include high range radiation monitoring.

APS Response to RAI B2.1.25-1

All radiation monitors within the scope of license renewal, except for two, are either Environmentally Qualified or are active components with no external high voltage, low signal cable. The two non-EQ area radiation monitors, RU-37 and RU-38, had previously been evaluated as low voltage instrument circuits and should have been evaluated as instrument circuits with sensitive, high voltage, low-level signals. The scope of AMP B2.1.25, Electrical Cables and Connectors Not Subject to 10 CFR 50.49 Environmental

Qualification Requirements Used in Instruments Circuits, has been revised to include the non-EQ area radiation monitors RU-37 and RU-38.

LRA Section A1.25, Commitment No.27 in Table A4-1, and Section B2.1.25 have been revised, as shown in LRA Amendment No. 9 in Enclosure 2, to include the non-EQ area radiation monitors within the scope of AMP B2.1.25, Electrical Cables and Connectors Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instruments Circuits. Calibration surveillance tests are used to manage the aging of the cable insulation and connections for non-EQ area radiation monitors within the scope of license renewal.

NRC RAI B2.1.25-2

Background:

The GALL Report, XI.E2, Detection of Aging Effects, states that in cases where a calibration or surveillance program does not include the cabling system in the surveillance, the applicant will perform cable system testing. In the LRA, AMP B2.1.25, under the same program attribute, the applicant states the ex-core neutron monitoring system is calibrated every 18 months in accordance with scheduled surveillance and maintenance testing procedures.

Issue:

The GALL Report recommends cables which are disconnected during scheduled surveillance are to be tested separately.

Request:

Are the ex-core neutron monitoring cables disconnected during the 18-month scheduled surveillance? If they are, is cable testing performed? If they are not, provide plant surveillance procedure that shows that these cables are not disconnected.

APS Response to RAI B2.1.25-2

The ex-core neutron monitoring cables are disconnected during the 18-month scheduled surveillance. AMP B2.1.25, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits, has been revised to require testing of the ex-core neutron monitoring cables.

LRA Section A1.25, Commitment No.27 in Table A4-1, and Section B2.1.25 have been revised to require testing of the ex-core neutron monitoring cables, as shown in LRA Amendment No. 9 in Enclosure 2. Cable tests such as insulation resistance testing or other tests are performed for detecting deterioration of the cable insulation system. The

cable will be tested prior to the period of extended operation and every 10 years thereafter. Acceptance criteria will be determined prior to testing based on the type of cable and type of test performed.

NRC RAI B2.1.26-1

Background:

The GALL Report, AMP XI.E3, states that the program applies to inaccessible medium voltage cables that are exposed to significant moisture. Significant moisture is defined as periodic exposures to moisture that last for more than a few days. AMP XI.E3 also states that periodic actions are taken to prevent cables from being exposed to significant moisture. AMP XI.E3 further states that inspection for water collection should be performed based on actual plant experience with water accumulation in the manhole with an inspection frequency of at least every two years.

Issue:

The staff's independent review and the applicant's operating experience review references condition reports/disposition request (CRDR) documenting cases of water intrusion and significant moisture (water intrusion and cable submergence) inconsistent with GALL AMP XI.E3 scope of program.

Request:

- Describe how PVNGS is consistent with the GALL Report, AMP XI.E3 program element, "Scope of Program," when cables are exposed to significant moisture (i.e., more than a few days).

- Describe how plant OE and CRDR documentation will be used to develop the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP to minimize the potential for inaccessible medium voltage cables to be exposed to significant moisture (i.e., inspection frequency determinations including periodic and event driven significant moisture exposure and corrective action).

APS Response to RAI B2.1.26-1

Request 1 Response

NUREG-1801, AMP XI.E3, Element 1 (Scope) states "This program applies to inaccessible (e.g., in conduit or direct buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with significant

voltage. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water)."

AMP B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Element 1 (Scope) states "The scope of this program includes all in-scope inaccessible medium voltage cables not subject to the environmental qualification requirements of 10 CFR 50.49 that are exposed to significant moisture (moisture that lasts more than a few days) simultaneously with significant voltage (energized greater than 25% of the time)." This is consistent with NUREG 1801 AMP XI.E3 Element 1.

LRA Sections A1.26 and B2.1.26 have been revised to reflect this response, as shown in LRA Amendment No. 9 in Enclosure 2.

Request 2 Response

Plant OE was used in the development of the inspection frequency for the AMP B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. PVNGS Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements aging management program Element 2 (Preventive Action) states "inspection for water collection within the cable manholes is being performed based on plant experience with water accumulation. The inspection frequencies will be established to be at least once every 2 years for all manholes within the scope of license renewal. If any of the manholes are found to contain water, the manholes are pumped dry, the source of the water is investigated, and the inspection frequency will be increased based on past experience."

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 lower megger readings. In all cases the splices were reworked. In addition, in one case, the splice was moved to a manhole subject to less water intrusion.

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. Manhole inspection frequency has been changed from a maximum five year interval to two years maximum. When a manhole is found to contain water, the frequency of inspection is changed to six months and the manhole is added to a "rain PM." The manhole is inspected any time there is a rain accumulation of greater than 3 inches in 24 hours and every six months until it has been found dry for two years. Additionally, the manhole found to contain water with submerged cables has had a seal replaced, lid raised above grade, and the ground surface reworked to route water away from the manhole.

LRA Sections A1.26 and B2.1.26 have been revised to reflect this response, as shown in LRA Amendment No. 9 in Enclosure 2.

NRC RAI B2.1.26-2

Background:

Standard Review Plan – License Renewal Section 3.6.2 includes acceptance criteria for evaluating the Updated Final Safety Evaluation Report (UFSAR) summary description including that the applicant has provided information equivalent to that in SRP-LR Table 3.6-2 including definitions of significant moisture, significant voltage, and minimum electrical manhole inspection frequencies.

Issue:

A staff review of the LRA, Appendix A, Section A1.26, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," finds the applicant's UFSAR summary description is not equivalent to SRP-LR Table 3.6-2 in that the applicant's summary description does not include definitions of significant moisture, significant voltage, and minimum electrical manhole inspection frequencies.

Request:

Discuss why LRA Appendix A, Section A1.26 summary description does not include definitions of significant moisture, significant voltage, and minimum electrical manhole inspection frequencies consistent with SRP-LR Table 3.6-2.

APS Response to RAI B2.1.26-2

LRA Sections A1.26 and B2.1.26 have been revised to include the definitions of significant moisture and voltage.

LRA Section A1.26, paragraph 1 was revised as follows, as shown in LRA Amendment No. 9 in Enclosure 2:

> "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 (moisture that lasts more than a few days) simultaneously with significant voltage (energized greater than 25% of the time) 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."

LRA Section B2.1.26, paragraph 1 was revised to read:

> "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 (moisture that lasts more than a few days) simultaneously with significant voltage (energized greater than 25% of the time) 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."

RAI No. B2.1.27-1 not used

NRC RAI B2.1.27-2

Background:

The GALL Report, AMP XI-S1, "ASME Section XI, Subsection IWE Program," Element 1, recommends inspection of containment pressure-retaining bolting.

Issue:

It is not clear from the review of PVNGS Program Evaluation Report B2.1.27 how the pressure retaining high strength bolts are monitored or inspected for aging management.

Request:

- Explain why pressure retaining high strength bolts are not included in Element 1 of PVNGS Program B2.1.27.
- Explain how the recommendations contained in EPRI NP-5769, EPRI TR -104213, and NUREG-1339 to prevent or mitigate degradation and failure of structural bolts with actual yield strength of 150,000 pounds per square inch are implemented for containment pressure retaining bolts.

APS Response to RAI B2.1.27-2

Request 1 Response

The program description in LRA Section B2.1.27 identifies that pressure retaining high strength bolts are inspected for aging management as part of the ASME Section XI, Subsection IWE Program. AMP B2.1.27, ASME Section XI, Subsection IWE, has been revised to add "pressure retaining bolting" to the list of in-scope components in Element 1.

Request 2 Response

There are no containment pressure retaining bolts used at PVNGS that are subject to the recommendations contained in EPRI NP-5769, EPRI TR -104213, and NUREG -1339. The operating experience addressed in these documents concerns bolting material with a yield strength above 150 ksi. PVNGS specifications specify that bolting subjected to the internal containment design pressure shall conform to ASME SA-320, Grade L43, or ASME SA-325. ASME SA-320, Grade L43 bolting material has a specified minimum yield strength of 105 ksi. ASME SA-325 bolting material has a specified minimum yield strength of 92 ksi or 81 ksi, depending on bolt size.

NRC RAI B2.1.27-3

Background:

In the GALL Report, AMP XI-S1, "ASME Section XI, Subsection IWE Program," Element 10 recommends that the applicant's ASME Section XI, Subsection IWE Program to consider OE.

Issue:

It is not clear from the review of PVNGS Program Evaluation Report B2.1.27 if the applicant has considered liner plate corrosion concerns identified in Information Notice (IN) 2004-09, and recent industry OE related to Beaver Valley Power Station for liner plate corrosion.

Request:

Explain if the applicability of IN 2004-09 and Beaver Valley Power Station containment liner plate corrosion has been considered for PVNGS, Units 1, 2, and 3, containments to avoid similar problems.

APS Response to RAI B2.1.27-3

During the 11th refueling outage for Unit 3, General Visual Examinations for Period 2 of the 1st Interval of the IWE Inservice Inspection Program were performed. Special attention was given to the areas at the floor level mentioned in IN 2004-09. No abnormal conditions or signs of degradation were observed. There were no areas that had evidence of water/moisture contacting the liner plate or penetrating the joint between the liner plate and the floor. Several areas at different elevations were also examined after the coating had been removed. These areas had scratches or blisters in the coating that required replacement of the coating. No signs of liner plate corrosion were detected in the base metal of the liner prior to re-coating. Before the outage EPRI performed a self assessment of the IWE/IWL Programs for all three Units and had no concerns. The EPRI

self assessment concluded that the IWE/IWL Programs are addressing all issues that are listed in IN 2004-09. No liner plate corrosion similar to the Beaver Valley operating experience has been identified at Palo Verde.

NRC RAI B2.1.27-4

Background:

In the GALL Report, AMP XI-S1, "ASME Section XI, Subsection IWE Program," Element 6 recommends that containment steel shell or liner loss exceeding 10 percent of the nominal wall thickness, or material loss projected to exceed 10 percent of the nominal wall thickness prior to the next examination, shall be documented. Such areas are to be accepted by engineering evaluation or corrected by repair/replacement activities in accordance with IWE-3122.

Issue:

PVNGS inspection report 09-VT-1004 documented local degradation of containment liner plate in Area 3 with loss of thickness of 0.04 inch. This local loss of thickness of 0.040 inch is more than 10 percent of the measured containment liner plate thickness of 0.263 to 0.27 inch minus the coating.

Request:

Explain the basis for acceptance of local loss of thickness of greater than 10 percent of the nominal wall thickness.

APS Response to RAI B2.1.27-4

The containment liner plate was examined to evaluate a minor loss of material, apparently caused by the removal of a temporary lug. This slight damage to the containment liner plate resulted from original construction activities. The depth of the gouge was found to exceed 10 percent of the nominal thickness. In support of the engineering evaluation, the surrounding area was examined by UT to determine the actual thickness of the liner, and the responsible engineer evaluated the condition in accordance with the design specification. It was deemed to be acceptable with no corrective action required. The damage was determined to not be aging related and not affect the ability of the liner plate to perform its intended function during the period of extended operation.

NRC RAI B2.1.28-1

Background:

In the GALL Report, AMP XI-S2, "ASME Section XI, Subsection IWL Program," Element 10 states that implementation of ASME Section XI, Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation.

Issue:

The PVNGS AMP B2.1.28, Element 10 states that existing PVNGS Tendon Integrity Surveillance procedures are regulated per and in compliance with RG 1.35.

Request:

Explain why PVNGS Tendon Integrity Surveillance procedures are regulated by RG 1.35 instead of 10 CFR 50.55a.

APS Response to RAI B2.1.28-1

LRA Section B2.1.28 addresses the ASME Section XI, Subsection IWL inspections performed in accordance with 10 CFR 50.55a. LRA Section B3.3 addresses the Concrete Containment Tendon Prestress program, which manages the loss of tendon prestress and is consistent with Regulatory Guide 1.35.1, Proposed Revision 0.

LRA Section B2.1.28 has been revised, as shown in LRA Amendment No. 9 in Enclosure 2, to delete the last paragraph in the operating experience discussion and replace it with the statement, "For discussion of IN 99-10, see Appendix B3.3, Concrete Containment Tendon Prestress." AMP XI.S2 has also been revised to incorporate this change.

NRC RAI B2.1.28-2

Background:

The GALL Report, AMP XI-S2, "ASME Section XI, Subsection IWL Program," Element 4, and ASME Section IWL-2410 require that the inspection of concrete surfaces are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five year intervals.

Issue:

The PVNGS AMP Program B2.1.28, Element 4 states that the plant is beyond 10 years of commercial operation and the frequency of concrete exams is 10 years, plus or minus

one year. Unit 1 will be inspected at five years, and every 10 years thereafter. Units 2 and 3 will be inspected at 10 years, and every 10 years thereafter.

Request:

Provide justification for this exception to the GALL and IWL requirement.

APS Response to RAI B2.1.28-2

The frequency of inspection for the ASME Section XI, Subsection IWL AMP is consistent with ASME Section XI Subsection IWL paragraph IWL-2421, Sites with Multiple Plants, which allows inspection intervals of every ten years staggered so that at least one unit is inspected every five years. Therefore, the existing program is consistent with ASME Section XI Subsection IWL and GALL, and no exception is required.

NRC RAI B2.1.29-1

Background:

IN 2009-04 discusses age-related degradation of mechanical constant supports observed at PVNGS, Unit 2.

Issue:

GALL Report AMP XI.S3 refers to the ASME Section XI, Subsection IWF and provides the requirements for ISI of all piping supports including constant supports. This program requires a periodic visual inspection. However, PVNGS license renewal aging management industry OE report for AMP XI.S3 (Document 2004-16) states that the degradation identified in IN 2009-04 for constant (spring) supports is not age-related.

Request:

Explain the basis of the statement made in Document 2004-16 that the constant supports degradation identified in IN 2009-04 is not age-related and does not affect the structural steel supports that transfer loads from the constant springs to the building structure. Include details of the root cause analyses for the mechanical constant supports identified in IN 2009-04. In addition, explain how the age-related degradation for other constant supports will be managed.

APS Response to RAI B2.1.29-1

The evaluation of IN 2009-04 is in progress. Although the root cause evaluation is not fully complete, the results to date indicate that the failure was not aging related, and the

apparent cause is a design issue involving the configuration of the supporting structural members. As the failure is not aging related, no changes to the AMP are required.

When the ASME Section XI, Subsection IWF inspection identified the degradation addressed by IN 2009-04, the scope of inspections was expanded in accordance with the requirements of ASME Section XI, Subsection IWF. No other constant spring supports were found to have the same condition. It was determined that the extent of condition was limited to four supports in each unit – one constant on each Main Steam line in each of the three units.

Upon completion of this evaluation, the appropriate corrective actions will be determined and completed in accordance with the PVNGS Corrective Action Program.

NRC RAI B2.1.32-1

Background:

Industry standards (e.g., ACI 349.3R-96) identified in the GALL Report Structures Monitoring Program suggest a five-year inspection frequency for structures exposed to natural environment, structures inside primary containment, continuous fluid-exposed structures, and structures retaining fluid or pressure, and a ten-year inspection frequency for below-grade structures and structures in a controlled interior environment.

Issue:

Element 4 of the applicant's Structures Monitoring Program states that inspections include SSCs that are identified for each topical area with frequencies that provide assurance that selected SSCs will not degrade or drastically change their ability to protect or support safety systems or components. The monitoring is scheduled to result in total observation of all systems on a frequency of approximately 10 years. To include a cross section of all three units, observations are conducted in different areas of different units. This ensures that within a thirty-year cycle, all units are monitored and all areas of each unit are monitored. It is not clear to the staff that all SSC's at each unit inspected under this AMP are in compliance with the industry standards inspection frequency (e.g., as noted in ACI 349.3R-96).

Request:

Please explain in more detail the inspection frequency for each unit and the plant in general. If the inspection interval exceeds the industry standard, clearly explain the basis for extending the interval and explain how the chosen interval will adequately manage aging during the period of extended operation.

APS Response to RAI B2.1.32-1

In summary of NUMARC 93-01 (which is endorsed by the NRC), structural degradation is mainly attributable to a combination of environmental and age related effects. The frequency and level of inspection should be based on the location/environment (temperature, radiation, water, freeze – thaw, chemicals, etc.), susceptibility of the material/structure to degradation, and the current age of the structure.

Chapter 6 (Evaluation Frequency) of ACI 349.3R-96 states in part, ... "Frequencies should be based on the aggressiveness of environmental conditions and physical conditions of the plant structures." .... "In general, it is recommended that all safety-related structures be visually inspected at intervals not to exceed 10-years."

The PVNGS structures are not subjected to sustained aggressive adverse environmental conditions.

As described in a plant procedure, 142 areas and 64 miscellaneous structures have been identified for each unit. By monitoring a minimum of 14 areas and 6 miscellaneous structures each year, a complete representative unit is inspected over every ten year period. To include a cross section of all three units, observations are conducted in different areas of different units. Also, other site programs (Appendix J, Appendix R [Fire Barriers / Penetration Seals], Appendix A [Fire Barriers], Settlement Monitoring, Fire Protection, Fire Doors, IWL Examinations, and Flood/High Energy Line Break/Radiation Barriers) look at Civil SSCs over and above that required by the Maintenance Rule. As documented in NRC Inspection Report 96-09, the NRC concluded that "the aggregation of the samples selected each year would result in a representative sample of all areas of the plant being examined over a 10-year period." The timeline below is representative of the inspection plan cycle.

- First Year of 30-Year inspection cycle: Baseline inspection completed and inspection of randomly selected area completed in year one in Unit 1.

- Tenth Year of 30-Year inspection cycle: Area randomly selected for inspection in Unit 1 (year one), inspected in Unit 2.

- Twentieth Year of 30-Year inspection cycle: Area randomly selected for inspection in Unit 1 (year one), inspected in Unit 3.

- Thirtieth Year of 30-Year inspection cycle: Area randomly selected for inspection in Unit 1 (year one), inspected again in Unit 1.

- For 20-Year Life Extension: Existing inspection plan cycle is applicable.

- Fortieth Year of additional 20-Year inspection cycle: Area randomly selected for inspection in Unit 1 (year one), inspected again in Unit 2.

- Fiftieth Year of additional 20-Year inspection cycle: Area randomly selected for inspection in Unit 1 (year one), inspected again in Unit 3.

NOTE: Transportable Conditions – A critical or adverse to quality deficiency in one unit will require an inspection of the corresponding area in the other two units.

NRC RAI B2.1.32-2

Background:

In the GALL Report AMP XI.S6, ACI 349.3R-96 is noted to provide an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes.

Issue:

Element 6 of the Structures Monitoring Program basis document provides guidance for the determination of performance criteria of SSCs included within the scope of the Maintenance Rule. SSCs deficiencies are categorized as minor, adverse, or critical and depending on the deficiency categorization the SSCs are considered to be acceptable or unacceptable. It is unclear to the staff if ACI 349.3R-96 provides the basis to establish the deficiency categorizations or if some other basis is utilized and what the criteria are to categorize a SSC deficiency as minor, adverse, or critical. This issue applies to all programs under the Structures Monitoring Program (i.e. RG 1.127 and Masonry Wall Programs).

Request:

Provide the criteria used to categorize a SCC deficiency as minor, adverse, or critical. Include references to the site documents or procedures which contain the categorization criteria.

APS Response to RAI B2.1.32-2

LRA Sections A1.32 and B2.1.32, and Commitment No. 34 in Table A4-1, have been revised, as shown in Amendment No. 9 in Enclosure 2, to add the following enhancement:

> Prior to the period of extended operation the Structures Monitoring Program will be enhanced to define the specific criteria for categorizing deficiencies for concrete inspections.

AMP XI.S6, Structures Monitoring Program, Element 6 has been revised to read as described below.

The PVNGS Structures Monitoring Program (SMP) provides guidance for the determination of performance criteria for SSCs included within the scope of the

Maintenance Rule. These guidelines were used to establish the inspection attributes for SSCs monitored by the PVNGS SMP and are listed in Element 3. The PVNGS SMP also uses Critical, Adverse, and Minor (see Element 4) to categorize levels of aging effect for each inspection attribute. Each inspection attribute has specific limits of aging effect defined for each category. The inspection methods, inspection frequency, and inspector qualifications are specified in the PVNGS SMP, which is consistent with ACI 349.3R-96 and ASCE 11-90.

Critical – A deficiency that requires corrective action (repair or more frequent inspection) to provide confidence that the associated structure will continue to perform its design function until the next regular inspection. For the purpose of this definition, the regular inspection interval is 10 years, (i.e., until the same structural element is reinspected in any unit), except for the spray ponds where the observation frequency is 5 years. A critical deficiency in one Unit area will precipitate an inspection of the corresponding structural elements in the other two Units.

Adverse – A deficiency that should be repaired (or inspected more frequently), when repair or more frequent inspection is not required to maintain the structure's functional capability. Such repairs may be done to prevent further degradation, maintain general material conditions, or to promote overall plant appearance. An Adverse deficiency in one Unit area will precipitate an inspection of the corresponding structural elements in the other two Units.

Minor – A deficiency that is acceptable as is, with no action required.

As an example of the application of the above deficiency categories, concrete components are condition-monitored to identify conditions of degradation as illustrated in ACI 201.1R-92. Deficiency categories for concrete are defined as follows:

Critical Deficiency – Conditions of degradation that must be repaired to continue to maintain the concrete component's functional capability or to restore the concrete component to its applicable functional capability. Transportability concerns shall be evaluated for all critical deficiencies.

Adverse Deficiency – Conditions of degradation that do not expose the embedded steel re-enforcement, do not impact the design function of the concrete component, or is passive (non-active condition) where it is not required to maintain the concrete component's functional capability. However, such repairs should be performed to prevent further degradation or to promote overall plant appearance.

Minor Deficiency – Conditions of degradation that do not expose the embedded steel re-enforcement, do not impact the design function of the concrete component, or is passive (non-active condition) shall be acceptable without further evaluation.

Structures will be categorized (a)(1) or (a)(2) per the Maintenance Rule as follows:

Acceptable Structure – A structure that is capable of performing its functions, and has no Critical deficiencies. Acceptable structures will normally be monitored in (a)(2).

Unacceptable structure – A structure or structural element that is presently unable to perform a structural function or that has one or more Critical deficiencies. An Unacceptable structure should be reviewed by the Maintenance Rule Expert Panel for (a)(1) goal setting and monitoring.

If a Critical or Adverse deficiency is identified in any unit, the corresponding structural elements in the other units will be inspected.

NRC RAI B2.1.32-3

Background:

IN 2004-05 identified leakage of spent fuel pools at several nuclear power plants.

Issue:

Spent fuel pool leakage has been identified at PVNGS since 1992. Leakage has been identified in the liner drain system as well as on the outer surfaces of the spent fuel pool concrete walls. Leakage through the spent fuel pool walls may degrade the concrete.

Request:

- Discuss any apparent cause analysis performed, if any, to identify the source of the leakage, as well as corrective actions taken to stop the leakage.
- Explain how the leakage has affected the condition of the concrete and what steps have been taken or will be taken to ensure adequacy of the concrete during the period of extended operation.
- Discuss any actions taken to ensure the leak chase system remains free and clear, allowing the system to properly prevent water from accumulating behind the liner.

APS Response to RAI B2.1.32-3

Background on Spent Fuel Pool (SFP) design and operation

The spent fuel pool (SFP) liner is constructed of welded steel plates, located in the concrete SFP (Reference ANSI N18.2-1973 and Palo Verde UFSAR). The radiological design basis for Palo Verde does not consider or allow for leakage from the SFP (stainless steel lined structure) into the environment. Therefore, any leakage from the SFP is captured by a leak-chase system and routed to the Radioactive Waste Drain (RD) System to provide a method of ensuring that leakage into the environment does not occur. The leak-chase system, or tell-tale system, is divided up into ten sections, and each section has an associated RD drain valve (RDN-V098 through RDN-V107). The RD valves associated with the spent fuel pool tell-tale system in all Units are kept closed.

On a daily basis, the tell-tale RD drain valves are opened and any accumulated water is drained, then the valves are reclosed. Any water is measured and recorded by Operations personnel, and trended by System Engineering. The water drained from the tell-tale lines is returned to the RD System.

Possible leakage through the liner plate welds imperfections was accounted for in the original design. The leak-detection system collects any water from slight liner leaks which can be isolated to one of the 10 sections associated with each drain valve. Because this leakage is being actively monitored and trended, only unanticipated changes or abnormal occurrences would be considered for an apparent cause analysis which would attempt to determine the source of the issue and initiate corrective actions as necessary.

Request 1 Response

SFP leakage occurred in Unit 1 in July 2005. This event, evaluated under Condition Report/Disposition Request (CRDR) 2814209, occurred when spent fuel pool tell-tale liner leakage water backed-up in the leak-chase system and flowed over the edges of the chase system embedded channels. This water with a sizable hydraulic head was forced through small cracks in the concrete walls of the fuel building subsequently releasing a small amount of borated water to the environment in two locations.

The cause of the water backing up in the leak chase system was due to a pressure test plug, employed since construction, which was lodged in the drain basin drain line, the same basin in place for the tell-tale RD drain valves. The plug was not allowing the basin to drain and Operations personnel did not have an alternate means of draining the water out of the basin. A decision was made to stop exercising the tell-tale drain valves until the issue was corrected.

As a consequence, the water, which would have normally been drained, accumulated in the leak chase channels. Due to the design and construction of the leak chase channels, water began to fill each leak chase channel. This water communicated with adjacent

channels via the small gap between the concrete wall and the liner plate. Eventually, the water made its way to the exterior face of the fuel pool walls using extremely small cracks in two locations. One of these locations was on the south side of the fuel pool inside of the fuel building, therefore, the leak was contained. The other leak location was on the east side of the fuel pool which is also the exterior wall of the fuel building.

The obstruction (plug) was removed from the drain basin drain line and a large amount of borated water was released from each RD tell-tale drain valve line (providing evidence that the leak chase lines were not obstructed) to the RD system for processing. This event was evaluated in the PVNGS corrective action program. The cause of the issue was identified and corrective actions were taken to eliminate and prevent further leakage to the environment.

Request 2 Response

The leakage of borated water to the environment from the Unit 1, July 2005 event did not have an adverse impact to the concrete as evaluated by a non-destructive examination performed by Construction Technology Laboratories (CTL). During the period of extended operation, Operations personnel will continue to measure and record RD tell-tale drain leakage on a periodic basis. System Engineering will continue to monitor and trend leakage. Abnormalities will be identified and investigated through the corrective action program to ensure issues are evaluated and corrected in a timely manner.

Request 3 Response

The RD tell-tale drain lines have been boroscope inspected in all Units between 2008 and 2009 with no blockage or water backup identified. A recurring engineering task, with maintenance support, has been developed to perform a boroscope inspection of the RD tell-tale drain lines on a 2-year frequency. Abnormalities will be identified, investigated, and corrected through the corrective action program to ensure a timely resolution. As previously indicated, monitoring and trending of tell-tale leakage will continue to be performed to identify and resolve potential issues.

It should be reiterated that the Unit 1, July 2005 event did not occur due to blockage in one or more of the leak-chase system drain lines, upstream of the RD tell-tale drain valves. The blockage occurred in the Radioactive Waste Drain to the Fuel Building Sump line which is directly downstream of the RD tell-tale drain valves.

NRC RAI B2.1.36-1

Background:

The GALL Report AMP, XI.S6, Structure Monitoring Program, recommends inspecting the exterior of metal enclosed bus (MEB) and accessible gaskets and sealant associated

with the exterior of MEBs. In the GALL XI.S6, Structure Monitoring Program, under acceptance criteria, it states that for each structure/aging effect combination, the acceptance criteria are selected to ensure that the need for corrective actions will be identified before loss of intended functions.

Issue:

Under Element 6, Acceptance Criteria, the applicant did not specify the acceptance criteria for inspecting the exterior of MEBs including gasket and sealants.

Request:

Provide acceptance criteria for inspecting the exterior of MEBs under Element 6.

APS Response to RAI B2.1.36-1

Element 6 of AMP B2.1.36 Aging Management Program for Metal Enclosed Bus has been revised to include acceptance criteria for inspecting the exterior of MEBs. The following paragraph has been added to Element 6 of AMP B2.1.36 Aging Management Program for Metal Enclosed Bus:

> "Visual inspection is the primary method for detecting external corrosion and material aging degradation. The exterior of MEBs will be inspected for general corrosion. No unacceptable indication of corrosion will be allowed to exist. For boots and gaskets discoloration, checkering, and cracking are indications of hardening. Physical manipulation during the visual inspection can also be used to verify the absence of hardening or cracking. No unacceptable indications of cracking will be allowed to exist. The program depends on the judgment and experience of the inspector to assess material condition. All unacceptable indications as a result of the inspection will be entered into the corrective action process."

NRC RAI B3.1-1

Background:

The Metal Fatigue of Reactor Coolant Pressure Boundary AMP in the GALL Report, Section X.M1, monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components in order not to exceed the design limit on fatigue usage.

Issue:

In the LRA, Appendix B, Section B3.1, states that 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, and an equivalent term I(t) is defined for valves in Paragraph NB 3552. However, ASME Boiler and Pressure Vessel, Section III, Subsection NB, Paragraph NB 3552 defines "Excluded Cycles," whereas ASME Boiler and Pressure Vessel, Section III, Subsection NB, Paragraph NB 3553 defines "Fatigue Usage."

Request:

Clarify which ASME Code section will be used in the calculation of the valve fatigue usage term I(t).

APS Response to RAI B3.1-1

Valve fatigue usage I(t) was calculated using ASME Boiler and Pressure Vessel, Section III, 1974 Edition, up to and including Winter 1975, Summer 1976, Section NB-3550, as shown on Table 4.3-9 on LRA pages 4.3-53 and 54.

The use of NB-3552 in Appendix B was a typographical error and has been corrected to NB-3550, as shown in Section B3.1 in LRA Amendment No. 9 in Enclosure 2.

NRC RAI B3.1-2

Background:

The Acceptance Criteria element of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP in Section X.M1 of the GALL Report, states that the acceptance criteria involves maintaining the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description.

Issue:

In the AMP basis document, Aging Management Program Evaluation Report, Metal Fatigue of Reactor Coolant Pressure Boundary (PVNGS-AMP-B.1-Revision 1), Section 3.6 states that the program acceptance criteria will be enhanced with action limits that further ensure that fatigue usage factors for reactor coolant pressure boundary components are maintained below the cumulative usage factor of 1.0 established by Section III Subsection NB of the ASME Boiler and Pressure Vessel Code, and that other limits assumed as the basis for safety determinations are maintained. The applicant did not provide a description of these "other limits."

Request:

What are the other limits that are assumed as the basis for safety determinations to be maintained as described in the enhanced Fatigue Management Program acceptance criteria?

APS Response to RAI B3.1-2

Other limits are those considerations not addressed as ASME Section III fatigue analyses that depend on an assumed number of load cycles, are still within the bounds of the ASME Code, but are not directly related to fatigue. Examples are the monitoring of crack propagation of an embedded flaw, and the determination of high energy line break locations. The basis for the action limits required in each case is outlined in the "Disposition" of each of these subsections of the LRA, with some details in the preceding text of the section.

The LRA identified the safety determinations listed below that are addressed as other limits in the metal fatigue monitoring program.

- High energy line break locations in Class 1 reactor coolant pressure boundary piping [LRA 4.3.2.14].
- The linear elastic fracture mechanics (LEFM) fatigue crack growth analysis of indications in a Unit 2 pressurizer support skirt forging weld [LRA 4.3.2.4].
- The fatigue crack growth and fracture mechanics stability analyses of half-nozzle repairs to alloy 600 material in reactor coolant hot legs [LRA 4.7.4].

NRC RAI B3.1-3

Background:

The Operating Experience element of Section X.M1 of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP in the GALL Report, Section X.M1 states that the program reviews industry experience regarding fatigue cracking. Applicable experience with fatigue cracking is to be considered in selecting the monitored locations. The NRC issued Regulatory Issue Summary (RIS) 2008-30 on the use of the Green's functions analysis methodology used to demonstrate compliance with ASME Code fatigue acceptance criteria and its nonconservatism when not correctly applied.

Issue:

The AMP basis document, Aging Management Program Evaluation Report, Metal Fatigue of Reactor Coolant Pressure Boundary (PVNGS-AMP-B.1, Revision 1), states that the

methods of the FatiguePro® software that utilizes a Green's transfer function to calculate the fatigue effects of transient cycles are used by the Fatigue Management Program. However, the applicant did not provide information whether it has reviewed RIS 2008-30 in its development of this AMP.

Request:

Describe how the RIS 2008-30 was considered in the development of the Fatigue Management Program and how the results of this review were incorporated into the enhanced Fatigue Management Program.

APS Response to RAI B3.1-3

Prior to the issuance of RIS 2008-30 on December 16, 2008, the PVNGS license renewal staff was aware of NRC staff concerns regarding the use of single element stress models to evaluate metal fatigue cumulative usage. Specifically, the staff had concerns with using single element stress models similar to those in FatiguePro® to perform an evaluation of NUREG-6260 locations. PVNGS performed an initial screening of the plant specific NUREG-6260 locations using the usage factors cited in the original ASME analyses, and due to their high environmentally assisted fatigue usage three of these locations were selected for further analysis. These locations (charging nozzle safe end, shutdown cooling elbow and pressurizer surge line elbow) were evaluated by an ASME III NB3200 three-dimensional, six-element analysis, and this action was considered satisfactory to address the NRC issues as understood at the time.

The PVNGS staff reviewed RIS 2008-30 in August 2009 and determined that no additional actions were required as a result of the RIS.

After further discussion between the NRC auditors and the APS team it was determined that the NRC staff concerns also applied to the FatiguePro® single element model being used in the stress based fatigue monitoring module of FatiguePro®. APS has decided to remove the text from the application that states FatiguePro® will be used to monitor stress based fatigue locations. LRA Sections A2.1 and B3.1, and Commitment 39 in Table A4-1, have been revised, as shown in Amendment 9 in Enclosure 2, to reflect a commitment to use a software monitoring program that incorporates a three-dimensional, six-element stress model. The selection of the software will be based upon available technology at the time of implementation and will conform to industry practices at the time of implementation.

NRC RAI B3.1-4

Background:

The Detection of Aging Effects element of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP in the GALL Report states that the program provides for periodic update of the fatigue usage calculations.

Issue:

The Program Description element states that the LRA, Section 4.3, AMP monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components. Subsection 4.3.1.4, "Present and Projected Status of Monitored Locations," of the LRA states that a composite worst-case (composite-unit) envelope of operating transients was created including only the highest accumulation of each transient experienced among the three units from 1985 through 2005. However, the applicant did not provide individual plant data for each unit that was used to develop the composite-unit envelope.

Request:

Provide the accumulation of transients for each of the three units that were used to develop the composite-unit envelope for the period from 1985 to 2005.

APS Response to RAI B3.1-4

Table RAI B3.1-4 below provides the individual unit transient accumulation through 2005 as compiled from the surveillance records, control room logs and monthly operating reports submitted to the NRC. During the compilation of this spreadsheet, several corrections were noted and changed in LRA Table 4.3-3, as shown in LRA Amendment No. 9 in Enclosure 2.

The composite worst-case unit accumulations presented in the LRA were determined by taking the best available data for each unit over two time periods. The first time period (1985-1995) used data from the recount effort (control room logs, work orders, and personnel interviews) to determine a more accurate accumulation than the 25% value assumed in the 1995 record of the transient count procedure. The second time period (1995-2005) used data from the 2005 record of the transient count procedure for each unit and supplemental data (control room logs, work orders, and personnel interviews) for new transients added to the enhanced program. The worst-case unit accumulation data (in any unit) for each of these time periods was then added to determine hypothetical composite worst-case unit accumulations for each transient. This has resulted in a composite worst-case unit accumulation greater than or equal to any one unit since in some cases the unit with the highest accumulation for the first time period may have been a different unit than the one with the highest accumulation for the second time period.

These composite unit worst-case accumulations from 1985-2005 were then divided by the number of years in operation (conservatively using 18 years for Unit 3) to get a hypothetical yearly accumulation rate. This hypothetical accumulation rate was then linearly projected to 40 and 60 years by multiplying the yearly accumulation rate by 22 and 42 respectively and added to the 2005 worst-case transient accumulations. This technique should have sufficient conservatism to bound the worst case scenarios for future projections.

Table B3.1-4
Palo Verde Nuclear Generating Station Transient Accumulation

No.	Transient	Unit 1 Accumulation (1985 – 2005)	Unit 2 Accumulation (1985 – 2005)	Unit 3 Accumulation (1985 – 2005)
	Normal Events			
1	Plant heatup, 100°F/hr	62	64	59
2	Plant cooldown, 100°F/hr	61	63	58
3	Plant loading, 5%/min	NR	NR	NR
4	Plant unloading, 5%/min	NR	NR	NR
5	10% step load increase	264	248	206
6	10% step load decrease	142	144	98
7	Normal plant variation	NR	NR	NR
8	RC Pump start (Hot Stby)	273	281	275
9	RC Pump stop (Hot Stby)	269	275	268
10	Cold Feedwater following Hot Standby (AFW)	3750	3752	3750
11	Pressurizer Heatup, 200°F/hr	86	83	77
12	Pressurizer Cooldown, 100°F/hr	85	82	76
13	Shift from Normal to Maximum Purification Flow at 100% Power	250	250	250
14	Low-Low Volume Control Tank/Charging Pump Suction Diversion to RWT	20	20	20
15	Pressure Level Control, Failure to Open	25	25	25
16	Unbolting/Bolting of RC Pump Casing Studs	19	19	19
17	Detensioning/ Tensioning of RV Head Studs	16	17	16
18	Safety Injection Check Valve Test	0	0	0
19	High Pressure Safety Injection Header Check Valve Test	0	NC	NC

Table B3.1-4
Palo Verde Nuclear Generating Station Transient Accumulation

No.	Transient	Unit 1 Accumulation (1985 – 2005)	Unit 2 Accumulation (1985 – 2005)	Unit 3 Accumulation (1985 – 2005)
20	Turbine Roll Test at Hot Standby	3	NC	2
21	Auxiliary Spray During Cooldown	85	82	76
22	Initiation of Shutdown Cooling	136	148	145
22.5	**Upset Events**			
23	Pump Coastdown at 100% power	NC	NC	NC
24	Reactor Trip	33	32	26
25	Loss of Reactor Coolant Flow	4	2	2
26	Loss of Load (Load Rejection from 100 to 15% Power)	6	7	14
27	Operating Basis Earthquake	0	0	0
28	Inadvertent CEA Drop	3	2	5
29	Inadvertent CEA Withdrawal	0	0	0
30	Loss of Charging and Recovery	7	0	2
31	Loss of Letdown and Recovery	17	18	10
32	Extended Loss of Letdown	64	1	2
33	Depressurization by Spurious Actuation of Pressurizer Spray Control Valves at 100% Power (Main & Aux. Spray)	0	1	1
34	Partial Loss of Condenser Cooling at 100% Power	1	0	0
35	Excess Feedwater at 100% Power	2	0	1
36	Turbine Trip w/out Reactor Trip	14	7	6
37	Inadvertent Actuation of Main Steam Line Isolation Valve (at 100% power/ at <100% power)	1/5	1/1	1/0
38	Opening One ADV or Steam Bypass Valve at 100% Power	2	1	0

Table B3.1-4
Palo Verde Nuclear Generating Station Transient Accumulation

No.	Transient	Unit 1 Accumulation (1985 – 2005)	Unit 2 Accumulation (1985 – 2005)	Unit 3 Accumulation (1985 – 2005)
39	Seismic Event up to & including One-Half of the Safe Shutdown Earthquake, at 100% Power	0	0	0
40	Initiation of Safety Injection	6	7	3
41	Inadv't Isolation of FW Heater	0	0	0
42	Loss of Feedwater Flow (to S/G)	9	8	11
43	Loss of RCP Seal Coolant	NR	NR	1
44	Loss of RCP Seal Injection	NR	NR	2
45	Inadvertent Auxiliary Spray at 100% Power	0	0	1
46	System Leak due to Rupture of Instrument Line or Sampling Connection	0	0	0
47	Inadvertent MFIV Closure at 100% Power (one MFIV)	1	0	0
48	Inadvertent FW or Condensate Pump Trip at 100% Power	7	8	11
49	MFIV Closures due to Loss of Air at 100% Power	1	0	0
50	Depressurization by MSSV at 100% Power	5	2	0
51	Startup of one Reactor Coolant Pump at 50% Power	0	0	0
52	Loss of Electrical Bus Supplying two RCPs at 100% Power	2	4	4
53	Inadvertent Closure of all MFIVs at 100% Power	NR	NR	NR
54	Spurious Start/Stop of SI Pump or Spurious Opening/Closing of SI Isolation Valve	0	1	0
54.5	**Test Events**			
55	Primary Side Hydrostatic Test, 3125 psia, 100°F – 400°F	1	1	1
56	Secondary Side Hydrostatic Test	3	3	3
57	Primary Side Leak Test, 2250 psia, 100°F – 400°F	5	4	2

Table B3.1-4
Palo Verde Nuclear Generating Station Transient Accumulation

No.	Transient	Unit 1 Accumulation (1985 – 2005)	Unit 2 Accumulation (1985 – 2005)	Unit 3 Accumulation (1985 – 2005)
58	Secondary Side Leak Test, 820 psia to design pressure	50	50	50
59	CVCS System Hydrostatic Test	1	1	NC
60	LPSI Pump Test	239	228	252
61	HPSI Pump Test	246	222	243

NC – transients not counted in the APS fatigue cycle count verification
NR – transients not recorded in the APS fatigue cycle count procedure

NRC RAI B3.1-5

Background:

The description of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP in the GALL Report states that the AMP monitors a sample of high fatigue usage locations.

Issue:

Section B3.1 of the LRA states that the locations in which fatigue effects are controlled by "a simple comparison" counting method are those with relatively low design fatigue usage values.

Request:

Provide the following additional information:

- Which locations have been selected for "a simple comparison" counting method,
- How these locations were selected, and
- Define the criteria used to classify fatigue usage values as relatively low fatigue usage values.

APS Response to RAI B3.1-5

Request 1 Response

The locations listed in Table 4.3-4 with "Fatigue Management Method" labeled "Global" are those locations monitored by the "simple comparison" counting method.

Request 2 Response

All locations with a current design fatigue analysis (see Table 4.3-4) were reviewed. Any locations with either low fatigue usage values (see below) or cumulative usage factor (CUF) bounded by a higher-usage location in the same plant system were selected for the "Global" monitoring method.

Request 3 Response

Locations were classified as "low fatigue usage" based on the following empirical criteria:

(a) Design CUF < 0.66*, or all of the criteria below were satisfied.

(b1) The maximum alternating stress intensity was low relative to the assumed number of cycles for the bounding transient pair(s)**, and

(b2) No new transients were identified, outside of the design set, which would cause any appreciable fatigue usage, and

(b3) Industry experience indicates that corresponding locations at similar plants typically have low design CUF values (e.g. < 0.66*).

Notes:

* CUF < 0.66 was used as the cutoff because such locations would still have CUF < 1.0 even if all plant cycles exceeded their design allowables by 1.5 times.

** Criterion (b1) is required because fatigue analyses can be performed with varying levels of conservative assumptions. Analysts frequently apply very conservative methods (e.g., transient lumping) for analysis of components with low fatigue duty. This can result in relatively high design CUF values at low fatigue-usage locations.

NRC RAI B3.1-6

Background:

The Scope of Program element of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP in the GALL Report, Section X.M1 indicates that the program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material. Section X.M1 of the GALL Report states that the AMP monitors a sample of high fatigue usage locations to include the locations identified in NUREG/CR-6260, as minimum, or alternatives proposed based on plant configuration.

Issue:

The AMP basis document, Aging Management Program Evaluation Report, Metal Fatigue of Reactor Coolant Pressure Boundary (PVNGS-AMP-B.1, Revision 1), and License Renewal Commitment No. 39 (LRA Table A4-1) state that the program will be enhanced to include additional locations with high calculated usage factor. However, the applicant did not identify the locations or provide justification for their use.

Request:

Provide additional information on:

- Which locations have been included into the Fatigue Management Program as enhancements to the program,
- How these locations were selected, and
- Define the criteria used to classify fatigue usage values as high fatigue usage values.

APS Response to RAI B3.1-6

Request 1 Response

All locations in Table 4.3-4 except location 17, the pressurizer spray nozzle, are being added as enhancements to the metal fatigue management program. The existing program includes a simplified cycle-based CUF calculation for the pressurizer spray nozzle in each unit. Fatigue in all other locations is currently being managed by manual cycle counting only, with current action levels at 90% of the number of cycles assumed by the design basis, but without application to specific locations.

Request 2 Response

All locations with a current design fatigue analysis (see LRA Table 4.3-4) were reviewed. Any locations which did not have low fatigue usage values (see response to RAI B3.1-5) or were identified in NUREG/CR-6260 were selected for explicit monitoring, using either CBF or SBF methodologies.

Request 3 Response

Locations were classified as "high fatigue usage" based on the following empirical criteria:

(a) Design CUF > 0.66*, and

(b) Maximum alternating stress intensity is high relative to the assumed number of cycles for the bounding transient pair(s)**, or either criteria (c) or (d) applies.

(c) New transients were identified, outside of the design set, that could cause appreciable additional fatigue usage, or

(d) Industry experience, i.e., corresponding locations at similar plants typically have high design CUF values (e.g. > 0.66*).

Notes:

* CUF < 0.66 was used as the cutoff because such locations would still have CUF < 1.0 even if all plant cycles exceeded their design allowable values by 1.5 times.

** Criterion (b) is required because fatigue analyses can be performed with varying levels of conservative assumptions. Analysts frequently apply very conservative methods (e.g. transient lumping) for analysis of components with low fatigue duty. This can result in relatively high design CUF values at low fatigue-usage locations.

NRC RAI B3.1-7

Background:

The Preventive Actions element of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP, Section X.M1 of the GALL Report states that maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains.

Issue:

The AMP basis document, Aging Management Program Evaluation Report, Metal Fatigue of Reactor Coolant Pressure Boundary (PVNGS-AMP.B1, Revision 1) and License Renewal Commitment No. 39 (LRA Table A4-1) state that the Fatigue Management Program will be enhanced with additional cycle count and fatigue usage action limit. The applicant does not provide information on what additional cycle count and fatigue usage action limit will be included into the Fatigue Management Program as enhancements to the program.

Request:

Provide the additional cycle count and fatigue usage action limit that will be included in the Fatigue Management Program as enhancements to the program.

APS Response to RAI B3.1-7

Currently, the surveillance test procedure requires action when 90% of the allowable cycles are achieved for any monitored transient. During extended operation, projections indicate that certain allowable cycles and fatigue limits may be approached. Therefore specific and targeted action limits are necessary to ensure actual fatigue limits are not exceeded. Those action limits have not yet been developed. As the transition to FatiguePro® is implemented, there are certain embedded administrative tools in FatiguePro® that will allow for specification of action limits based on projected fatigue usage at specific locations that account for actual cumulative fatigue. The action limits can be based on the time required to implement expected or projected mitigating actions (such as component replacements or revisions to ASME Code Fatigue Analysis of Record) prior to actual fatigue limits being exceeded.

NRC RAI B3.1-8

Background:

The Parameters Monitored/Inspected element of the Metal Fatigue of Reactor Coolant Pressure Boundary AMP, Section X.M1 of the GALL Report states that the program monitors all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The number of plant transients that cause significant fatigue usage for each critical reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient.

Issue:

The AMP basis document, Aging Management Program Evaluation Report, Metal Fatigue of Reactor Coolant Pressure Boundary (PVNGS-AMP-B.1, Revision 1), states that the scope of the Fatigue Management Program will be enhanced with a revised list of monitored plant transients that contribute to high usage factor. This enhancement is not described in Commitment No. 39 for the Fatigue Management Program.

Request:

Provide additional information on how Commitment No. 39 will be revised to incorporate the enhancement to the Parameters Monitored/Inspected element of the Fatigue Management Program on the revised list of monitored plant transients that contribute to high usage factor. In addition, clarify the implementation schedule for the fatigue usage calculations described in License Renewal Commitment No. 39.

APS Response to RAI B3.1-8

LRA Table A4-1, Commitment No. 39, has been revised as follows, and as shown in LRA Amendment No. 9 in Enclosure 2:

No later than two years prior to the period of extended operation:

(1) The existing Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to provide guidelines and requirements for tracking both transient cycle counts and fatigue usage of selected components using the FatiguePro® software, to maintain the fatigue cumulative usage factor of these components less than 1.0. The enhanced program will include tracking of cumulative usage, counting of transient cycles, manual recording of selected transients, review of plant cycle data and review of the resulting usage factor data.

(2) The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. A fatigue monitoring software program that incorporates a three-dimensional, six-element model meeting ASME III NB 3200 requirements will be used for stress-based fatigue monitoring (SBF).

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

listed in Table 4.3-4 "Summary of Fatigue Usage from Class 1 Analyses, and Method of Management by the Metal Fatigue of Reactor Coolant Pressure Boundary Program."

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

NRC RAI B3.2-1

Background:

GALL AMP X.E1 states that aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAA) per license renewal. GALL AMP X.E1 further states that under 10 CFR 54.21(c)(1)(iii), plant EQ programs, which implement the requirements of 10 CFR 50.49 are viewed as AMPs for license renewal. Pursuant to 10 CFR 54.21(c)(1)(iii), an applicant must demonstrate that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Applicant Commitment No. 40 states that maintaining qualification through the extended license renewal period requires that existing EQ evaluations be re-evaluated prior to the period of extended operation.

Issue:

In the LRA, Commitment No. 40 is inconsistent with license renewal commitments for existing programs in that the existing EQ program is considered a TLAA and an AMP but is not credited for license renewal in the applicant's commitment and is shown implemented prior to the period of extended operation.

Request:

Discuss why license renewal Commitment No. 40 does not first reference the existing EQ program as an ongoing program, in addition to performing the re-evaluations of the existing EQ calculations prior to the period of extended operation.

APS Response to RAI B3.2-1

LRA Table A4-1, Commitment No. 40, has been revised to credit the EQ program for license renewal, as shown in Amendment No. 9 in Enclosure 2.

NRC RAI B3.3-1

Background:

GALL Report (NUREG-1801), Section X.S1, "Concrete Containment Tendon Prestress," states that IN 99-10 provides guidance for constructing the trend line. However, PVNGS Program B3.3, Element 5 states that the Concrete Containment Tendon Prestress Program documents will be enhanced to require a regression analysis for each tendon group after every surveillance. The updated documents will also describe the joint regression analysis methods used to construct the lift-off trend lines, including the use of individual tendon data in accordance with
IN 99-10 Attachment 3.

Issue:

PVNGS performed tendon surveillance for Units 1, 2, and 3 during 2008, 2006, and 2002, respectively. However, according to PVNGS AMP B3.3, Element 5, the Containment Tendon Prestress Program documents has not been revised until now.

Request:

Please provide the status and conclusions of the regression analysis performed in accordance with IN 99-10.

APS Response to RAI B3.3-1

The regression analyses of tendon lift-off data were performed in support of the PVNGS LRA. The regression analyses of surveillance data are consistent with Information Notice (IN) 99-10. The program will be enhanced to continue to compare regression analysis trend lines of the individual lift-off values of tendons surveyed to date, in each of the vertical and hoop tendon groups. This enhancement is documented in LRA Table A4-1, Commitment No. 41, and LRA Section B3.3.

The most recent results of the Concrete Containment Tendon Prestress Program are documented in Palo Verde Work Order Inspection Reports. A regression analysis of the lift-off data to date was extended to 60 years, and demonstrated that average prestress in both the vertical tendon group and the horizontal cylinder and horizontal dome tendon subgroups should remain above the applicable minimum required values for at least 60 years of operation; and that all tendons should therefore maintain their design basis function for the extended period of operation.

NRC RAI 4.4-1

Background:

NUREG-1800, "Generic Aging Lessons Learned (GALL) Report," AMP X.E.1, "Environmental Qualification of Electric Components," and NUREG-1801, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Table 4.4.2, "Examples of Final Safety Analysis Report Supplement for Environmental Qualification of Electrical Equipment Time-Limited Aging Analysis Evaluation," include re-analysis attributes for an EQ program implemented in accordance with 10 CFR 54.21(c)(1)(iii). The PVNGS LRA, Section 4.4, "Environmental Qualification of Electric Equipment," states that the aging management program to be applied to EQ electrical equipment will be implemented in accordance with 10 CFR 54.21(c)(1)(iii) and includes re-analysis attributes consistent with NUREG-1800 and NUREG-1801.

Issue:

Although LRA, Section 4.4, includes the NUREG-1801 re-analysis attributes, Appendix A, "Updated Final Safety Analysis Report Supplement," Sections A2.2, "Environmental Qualification of Electrical Components," and A3.3, "Environmental Qualification of Electrical Components," do not. If the UFSAR supplement were incorporated as is, the UFSAR described AMP and TLAA for EQ of electrical components would be inconsistent with that described in the LRA, NUREG-1800, and NUREG-1801.

Request:

Revise the description of the EQ of electrical components AMP and TLAA program descriptions in LRA Sections A2.2 and A3.3 to include the re-analysis attributes discussed in LRA Section 4.4, NUREG-1800, and NUREG-1801.

APS Response to RAI 4.4-1

LRA Sections A2.2 and A3.3 have been revised, as shown in Amendment No. 9 in Enclosure 2, to include the following:

> "Reanalysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the EQ Program. Important attributes for the reanalysis of aging evaluations include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met)."

ENCLOSURE 2

Palo Verde Nuclear Generating Station
License Renewal Application Amendment No. 9

PVNGS LRA Amendment No. 9
Affected Pages

LRA Section	Affected LRA Page Nos.	RAI
Table 3.2.2-4	3.2-38 and 39	B2.1.4-1
3.3.2.1.9	3.3-12	B2.1.20-3
Table 3.3.1	3.3-58	B2.1.20-3
Table 3.3.2-9	3.3-122 and 123	B2.1.20-3
4.3.1	4.3-2, 3, 4, 5	B3.1-3
4.3.1.2	4.3-6	B3.1-3
4.3.1.4	4.3-11	B3.1-4
Table 4.3-3	4.3-12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 21A	B3.1-4
4.3.1.5	4.3-22 and 24	B3.1-3
Table 4.3-4	4.3-29	B3.1-3
A1.2	A-2 and A-3	B2.1.2-1
A1.13	A-7 and A-8	n/a
A1.19	A-11 and A-11A	B2.1.19-1 B2.1.19-2
A1.25	A-15	B2.1.25-1 B2.1.25-2
A1.26	A-15 and 16	B2.1.26-1 B2.1.26-2
A1.32	A-18	B2.1.32-2
A2.1	A-21, 22, 23	B3.1-3 B3.1-8
A2.2	A-23	4.4-1
A3.3	A-37 and 38	4.4-1

LRA Section	Affected LRA Page Nos.	RAI
A4, Table A4-1 No. 4	A-42	B2.1.2-1
A4, Table A4-1 No. 15	A-45	n/a
A4, Table A4-1 No. 27	A-51	B2.1.25-1 B2.1.25-2
A4, Table A4-1 No.34	A-52	B2.1.32-2
A4, Table A4-1 No.39	A-54	B3.1-3 B3.1-8
A4, Table A4-1 No. 40	A-55	B3.2-1
B2.1.2	B-14, 15, 16, 17	B2.1.2-1
B2.1.7	B-27, 28, 29	B2.1.7-02
B2.1.10	B-37, 38, 39, 40, 41, 42	B2.1.10-3
B2.1.13	B-48, B-49, B-50	n/a
B2.1.19	B-62, 63	B2.1.19-1 B2.1.19-2
B2.1.24	B-72, 73	B2.1.24-1
B2.1.25	B-74, 75	B2.1.25-1 B2.1.25-2
B2.1.26	B-76, 77	B2.1.26-1 B2.1.26-2
B2.1.28	B-82, 83	B2.1.28-1
B2.1.32	B-92, 93, 94	B2.1.32-2
B3.1	B-114, 115, 116, 117, 118, 119	B3.1-1 B3.1-3 B3.1-8

Source: RAI B2.1.4-1

Table 3.2.2-4, Engineered Safety Features – Summary of Aging Management Evaluation – Safety Injection and Shutdown Cooling System (page 3.2-38), is revised as follows (new text underlined):

Table 3.2.2-4 Engineered Safety Features – Summary of Aging Management Evaluation – Safety Injection and Shutdown Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Shutdown Cooling)	PB	Carbon Steel with Stainless Steel Cladding	Borated Water Leakage (Ext)	Loss of material	Boric Acid Corrosion (B2.1.4)	V.D1-1	3.2.1.45	A
Heat Exchanger (Shutdown Cooling)	PB	Carbon Steel with Stainless Steel Cladding	Treated Borated Water (Int)	Loss of material	Water Chemistry (B2.1.2)	V.D1-30	3.2.1.49	~~A~~C

Table 3.2.2-4, Engineered Safety Features – Summary of Aging Management Evaluation – Safety Injection and Shutdown Cooling System (page 3.2-39), is revised as follows (new text underlined):

Table 3.2.2-4 Engineered Safety Features – Summary of Aging Management Evaluation – Safety Injection and Shutdown Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Shutdown Cooling)	PB	Carbon Steel with Stainless Steel Cladding	Treated Borated Water (Int)	Cracking	Water Chemistry (B2.1.2)	V.D1-31	3.2.1.48	~~A~~C

Source: RAI B2.1.20-3 Response

LRA Section 3.3.2.1.9, Compressed Air System (page 3.3-12), is revised as follows (new text underlined):

Environment

The compressed air system component types are exposed to the following environments:

- Dry Gas
- Plant Indoor Air
- Wetted Gas

Aging Management Programs

The following aging management programs manage the aging effects for the compressed air system component types:

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

Source: RAI B2.1.20-3 Response

LRA Table 3.3.1, Auxiliary Systems – Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems (page 3.3-58), is revised as follows (new text underlined):

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1.53	Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	~~Not applicable. PVNGS has no in-scope steel compressed air system piping, piping components and piping elements exposed to condensation (internal), so the applicable NUREG-1801 line was not used.~~ Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components (B2.1.22) is credited.

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1.54	Stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation	Loss of material due to pitting and crevice corrosion	Compressed Air Monitoring	No	~~Not applicable. PVNGS has no in-scope steel compressed air system piping, piping components and piping elements exposed to condensation (internal), so the applicable NUREG-1801 line was not used.~~ Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components (B2.1.22) is credited.

Source: RAI B2.1.20-3 Response

LRA Table 3.3.2-9, Auxiliary Systems – Summary of Aging Management Evaluation – Compressed Air System (pages 3.3-122 and 123), is revised as follows (new text underlined):

Table 3.3.2-9 Auxiliary Systems – Summary of Aging Management Evaluation – Compressed Air System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Accumulator	PB	Carbon Steel	Dry Gas (Int)	None	None	~~VII.J-22~~ VII.J-23	~~3.3.1.98~~ 3.3.1.97	A, 2
Orifice	PB, ~~SIA,~~ TH	Stainless Steel	Dry Gas (Int)	None	None	~~VII.J-18~~ VII.J-19	~~3.3.1.98~~ 3.3.1.97	A, 2
Orifice	SIA	Stainless Steel	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.D-4	3.3.1.54	E, 1
~~Piping~~	~~PB, SIA~~	~~Carbon Steel~~	~~Dry Gas (Int)~~	~~None~~	~~None~~	~~VII.J-22~~	~~3.3.1.98~~	~~A~~
Piping	PB, SIA	Carbon Steel	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.D-2	3.3.1.53	E, 1
~~Piping~~	~~SIA~~	~~Copper Alloy~~	~~Dry Gas (Int)~~	~~None~~	~~None~~	~~VII.J-3~~	~~3.3.1.98~~	~~A~~
Piping	SIA	Copper Alloy	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.G-9	3.3.1.28	E
Piping	PB, SIA	Stainless Steel	Dry Gas (Int)	None	None	~~VII.J-18~~ VII.J-19	~~3.3.1.98~~ 3.3.1.97	A, 2

Table 3.3.2-9 Auxiliary Systems – Summary of Aging Management Evaluation – Compressed Air System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB, SIA	Stainless Steel	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.D-4	3.3.1.54	E, 1
Tubing	PB	Stainless Steel	Dry Gas (Int)	None	None	~~VII.J-18~~ VII.J-19	~~3.3.1.98~~ 3.3.1.97	A, 2
~~Valve~~	~~PB, SIA~~	~~Carbon Steel~~	~~Dry Gas (Int)~~	~~None~~	~~None~~	~~VII.J-22~~	~~3.3.1.98~~	~~A~~
Valve	PB, SIA	Carbon Steel	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.D-2	3.3.1.53	E, 1
~~Valve~~	~~SIA~~	~~Copper Alloy~~	~~Dry Gas (Int)~~	~~None~~	~~None~~	~~VII.J-3~~	~~3.3.1.98~~	~~A~~
Valve	SIA	Copper Alloy	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.G-9	3.3.1.28	E
Valve	PB~~, SIA~~	Stainless Steel	Dry Gas (Int)	None	None	~~VII.J-18~~ VII.J-19	~~3.3.1.98~~ 3.3.1.97	A, 2
Valve	PB, SIA	Stainless Steel	Wetted Gas (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.D-4	3.3.1.54	E, 1

Notes for Table 3.3.2-9:

Standard Notes:

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

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

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.

F Material not in NUREG-1801 for this component.

Plant Specific Notes:

1 AMP XI.M24, "Compressed Air Monitoring" applies to monitoring the piping and components associated with the air compressors and dryers. The air compressor, dryer piping and components are not in-scope for Palo Verde. In-scope piping and components for Palo Verde are associated with containment penetrations and nitrogen gas piping/components for backup to the spent fuel pool gate seals. Therefore XI.M24 is not considered appropriate to Palo Verde and alternate AMPs are specified for the in-scope piping and components.

2 The dry gas internal environment applies to components associated with the safety-related backup nitrogen supply to the spent fuel pool gate seals.

Source: RAI B3.1-3 Response

LRA Section 4.3.1, Fatigue Aging Management Program (page 4.3-2), first paragraph, is revised to read (incorrect text is struck out, new text is underlined, first paragraph is broken into three new paragraphs):

"No later than two years p~~P~~rior to the period of extended operation, the Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include an ~~FatiguePro®~~ automated and computerized cycle counting and fatigue usage factor tracking and management program. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. ~~The enhanced program will support safe operation of PVNGS for the period of extended operation, as summarized in Section 4.3.1.5 and Appendix B, Section B3.1.~~

"For stress-based fatigue monitoring (SBF), APS commits to the use of a fatigue monitoring software program that incorporates a three-dimensional, six-element model meeting ASME III NB-3200 requirements, and commits to the implementation of this method for SBF monitoring at least two years prior to the period of extended operation.

"The enhanced program will monitor...."

LRA Section 4.3.1, Fatigue Aging Management Program (page 4.3-3), "Scope," is revised to read (incorrect text is struck out, new text is underlined):

"The PVNGS ~~FatiguePro®~~ Metal Fatigue of Reactor Coolant Pressure Boundary program will monitor the components and piping listed in Table 4.3-4.

LRA Section 4.3.1, Fatigue Aging Management Program (pages 4.3-4 and 4.3-5), "Bounding Parameters for Transients," paragraphs 2 and 3 are revised to read (incorrect text is struck out, new text is underlined):

"Since ~~the FatiguePro®~~ an automated six-element stress-based fatigue calculation ~~approximates~~ will calculate stresses from the actual event severity, usage factors reported by ~~FatiguePro®~~ the program at locations for which the stress-based method is used ~~are generally~~ will be more realistic than values predicted by the code analysis for the same number of cycles, or which would be determined by cycle-count monitoring.

"The ~~FatiguePro®~~ stress-based algorithms ~~are conservative and therefore also bound~~ will accurately calculate the actual fatigue effects. The automated six-element stress monitoring software will use the same methods as ~~A~~an ASME III code analysis to calculate~~s~~ a three-dimensional, six-component state of stress at critical locations monitored by the SBF methodology. ~~The FatiguePro® stress-based algorithms approximate the effects of this state~~

~~of stress with a conservative approximation of the largest principal stress that would be expected in a given location for a given loading condition, and calculates alternating stress ranges and usage factors using this approximate largest principal stress. This ensures that the FatiguePro® stress-based algorithms are conservative and therefore also bound the actual fatigue effects. Test cases for several nuclear units in process of license renewal have demonstrated that the method produces conservative values of this largest principal stress, and therefore of the calculated fatigue usage, when compared to a three-dimensional, six-component calculation using code methods.~~"

LRA Section 4.3.1.2, Enhanced PVNGS Fatigue Management Program (page 4.3-6), paragraph 1, is revised to read (incorrect text is struck out, new text is underlined):

"The enhanced fatigue management program (Metal Fatigue of Reactor Coolant Pressure Boundary program) will include~~s a FatiguePro®~~ an automated and…."

Source: RAI B3.1-4 Response

LRA Section 4.3.1.4, Present and Projected Status of Monitored Locations (page 4.3-11), is revised as follows (incorrect text is struck out, new text is underlined):

number of years of operation up to 2005 (Unit 3, operating period of 18 years). This resulted in the worst-case accumulation of cycles over the least amount of time. This accumulation rate was then multiplied by 22 (18+22=40) and added to the composite-unit 2005 accumulation to calculate the projected accumulation at 40 years of operation. Similarly, the accumulation rate was multiplied by 42 (18+42=60) and added to the composite-unit 2005 accumulation to calculate the projected accumulation at 60 years of operation.

***Transients not included in* the FSAR**

Some transients which are required by the fatigue management program to accurately calculate fatigue usage are not required to be monitored by the PVNGS FSAR, and were therefore not separately counted in the procedure through 2005. These transients were therefore included in the cycle count verification. However, there is no accumulation record of these transient events from 1996 through 2005. APS has therefore determined ~~an accumulation rate using the recount~~ accumulation data from 1985 through ~~1995~~2005, the accumulation rate was then calculated by dividing this accumulation by the least number of years of operation up to ~~1995~~2005 (Unit 3, operating time of 18 years). ~~The composite unit 2005 accumulation was then calculated by multiplying the accumulation rate by 10 years (1995 to 2005) and adding this to the 1995 recount accumulation.~~

***Transients with a to date accumula*tion of zero**

The yearly accumulation rate for transients which to date have no accumulation was determined by dividing the design basis number of transient events by 40 years. This resulted in the original expected annual accumulation rate of transients, except that no transients have occurred to date. Therefore, the accumulation rate was determined by multiplying the original expected accumulation rate by the percentage of years left in the design basis (22/40).

***Transients not expected to* occur**

No yearly accumulation rate was calculated for transients which are not expected to occur. For these transient events at least one event was assumed to occur during the period of extended operation.

Source: RAI B3.1-4 Response

LRA Table 4.3-3, APS Fatigue Cycle Count Verification (Composite Worst-Case Unit), and Projections (pages 4.3-11 to 21A), is revised as follows (incorrect text is struck out, new text is underlined):

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
Normal Events								
1. Plant Heatup, 100°F/hr	500	21	64	NC[9]	64[10]	3.56	143	214
2. Plant Cooldown, 100°F/hr	500	20	63	NC	63[10]	3.50	140	210
3. Plant Loading, 5%/min	15,000	NR[11]	NR	NC	NC	NC	NC	NC
4. Plant Unloading, 5%/min	15,000	NR	NR	NC	NC	NC	NC	NC
5. 10% Step Load Increase[12]	2,000	500	521	~~132~~264[13]	~~297~~264[13]	~~16.50~~14.67	~~660~~587	~~990~~880
6. 10% Step Load Decrease[12]	2,000	NR	NR	~~72~~144[13]	~~162~~144[13]	~~9.00~~8.00	~~360~~320	~~540~~480
7. Normal Plant Variation	10^6	NR	NR	NC	NC	NC	NC	NC
8. RC Pump Starting	1,000	250	281	NC	281[14]	15.61	625	937

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
9. RC Pump Stopping	1,000	250	275	NC	275[14]	15.28	612	917
10. Cold Feedwater Following Hot Standby (AFW)	15,000	3750	3752	NC	3752[14]	208.44	8,338	12,507
11. Pressurizer Heatup, 200°F/hr	500	NR	86	NC	86[10]	4.78	192	287
12. Pressurizer Cooldown, 200°F/hr	500	NR	85	NC	85[10]	4.72	189	284
13. Shift from Normal to Maximum Purification Flow at 100% Power	1,000	250	250	NC	250[14]	13.89	556	834
14. Low-Low Volume Control Tank/ Charging Pump Suction Diversion to RWT	80	20	20	NC	20[14]	1.11	45	67
15. Pressure Level Control, Failure to Open	100	25	25	NC	25[14]	1.39	56	84

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
16. Unbolting/ Bolting of RC Pump Casing Studs	25	NR	NR	19	19[15]	1.06	**43**[16]	**64**[16]
17. Tensioning/ Detensioning of RV Head Studs	50	NR	NR	~~9~~17[13]	~~21~~17[13]	~~1.13~~0.94	~~45~~38	**~~68~~57**[16]
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	0	0	[18]	1	1
20. Turbine Roll Test at Hot Standby	10	NR	NR	3	3	[18]	4	4
21. Auxiliary Spray During Cooldown	500	NR	NR	~~63~~85[27]	~~142~~85[27]	~~7.88~~[13]4.72	~~315~~189	~~473~~284
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]

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
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]
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~~10	0	~~1~~0	~~0.06~~[18]	~~3~~1	~~4~~1
30. Loss of Charging and Recovery	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]	64[26]	~~NC~~2	~~64~~66[26]	~~3.56~~3.67	~~143~~147	~~214~~220

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
33. Depressurization by Spurious Actuation of Pressurizer Spray Control Valve at 100% Power (Main & Aux. Spray)	40	10	11	0	1	0.11	5	7
34. Partial Loss of Condenser Cooling at 100% Power	40	10	11	NC	11[14]	0.61	25	37
35. Excess Feedwater at 100% Power	40	10	10	2	2	0.11	5	7
36. Turbine Trip Without Reactor Trip	40	10	15	13	18	1.00	**40**[16]	**60**[16]
37. Inadvertent Actuation of Main Steam Line Isolation Valve	5/40[21]	2	3	1/5	1/5	0.06/0.28	3/12	4/17

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
38. Opening One ADV or Steam Bypass Valve, at 100% Power	40	10	11	1	2	0.11	5	7
39. Seismic Event up to and Including One-Half of the Safe Shutdown Earthquake, at 100% Power	2	NR	NR	NC	NC	[22]	NC	NC
40. Initiation of Safety Injection	10	NR	7	4	7[10]	0.39	**16**[16]	**24**[16]
41. Inadvertent Isolation of FW Heater	5	1	1	0	0	0.07[19]	2	3
42. Loss of Feedwater Flow to Steam Generators	85	21	22	~~NC~~12	~~NC~~13[23]	0.72~~[23]~~	~~NC~~29	~~NC~~44
43. Loss of RCP Seal Coolant	40	NR	NR	NC	NC	NC	NC	NC
44. Loss of RCP Seal Injection	40	NR	NR	NC	NC	NC	NC	NC

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
45. Inadvertent Auxiliary Spray at 100% Power	5	1	2	0	1	0.06	3	4
46. System Leak due to Rupture of Instrument Line or Sampling Connection	40	10	10	0	0	0.55[19]	13	24
47. Inadvertent MFIV Closure at 100% Power (One MFIV)	40	10	10	1	1	0.06	3	4
48. Inadvertent FW or Condensate Pump Trip at 100% Power	40	10	11	10	11	0.61	25	37
49. MFIV closures due to Loss of Air at 100% Power	5	1	1	1	1	0.06	3	4
50. Depressurization by MSSV at 100% Power	10	2	2	5	5	0.28	**12**[16]	**17**[16]

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
51. Startup of one Reactor Coolant Pump at 50% Power	10	NR	NR	NC	NC	0.14[19]	4	6
52. Loss of Electrical Bus Supplying two RCPs at 100% Power	40	10	14	2	6	0.33	14	20
53. Inadvertent Closure of all MFIVs at 100% Power	5	NR	NR	NC	NC	[24]	NC	NC
54. Spurious Startup/ Shutdown of SI Pump or Spurious Opening/ Closing of SI Isolation Valve	40	10	10	1	1	0.06	3	4
Test Events								
55. Primary side Hydrostatic Test, 3125 psia, 100-400F	10	NR	1	NC	1[10]	[18]	2	2

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

Transient[3]	Limiting Number of Events (Table 4.3-2)	Fatigue Management Program Transient Cycle Count Procedure (73ST-9RC02)		Worst-Case APS Transient 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					
56. Secondary Side Hydrostatic Test	10	3	3	1	1	(18)	2	2
57. Primary Side Leak Test, 2250 psia, 100-400F	200	NR	5	NC	5[10]	(18)	6	6
58. Secondary Side Leak Test, 820 psia to design pressure	200	50	50	1	1	(18)	2	2
59. CVCS System Hydrostatic Test	40	10	10	1	1	(18)	2	2
60. LPSI Pump Test	500[25]	125	~~239~~268	~~44~~125	~~84~~268	~~4.00~~[25] 14.89	~~172~~**596**[16]	~~252~~**894**[16]
61. HPSI Pump Test	500[25]	125	~~246~~261	~~44~~125	~~84~~261	~~4.00~~[25] 14.50	~~172~~**580**[16]	~~252~~**870**[16]

1 The FSAR and design specifications also include Faulted and Emergency transient events. These events are not included here because they are not used in ASME III Class 1 fatigue analyses.

2 Results of all calculated transient cycles were rounded up to the next integer (i.e., 11.3=12 or 26.7=27). Projections are correct but may appear low, because the calculated accumulation rates were rounded to two decimals.

3 Un-bolded transients do not contribute significantly to fatigue and therefore are not necessary for calculation of fatigue by the fatigue management program.

4 The "Composite Worst-Case Unit Accumulation" column was determined by review of the 2005 record of the cycle count procedure, unless otherwise noted. The highest transient totals recorded in the 1995 record were deleted from the highest totals in the 2005 record to remove the

25% accumulation assumed in 1995. Then the APS recount from 1985 through 1995 was added to the result to obtain the best estimate of the worst-case number of events experienced.

[5] The "Accumulation Rate," for all transients counted in the cycle count procedure that have an accumulation through 2005, was calculated by dividing the "Composite Worst-Case Unit Accumulation" by the least number of years in operation up to 2005 (Unit 3 operating period of 18 years) to determine the worst case number of events experienced per year.

[6] The "Projected to 40 years" column was calculated by multiplying the "Accumulation Rate" value by 22 years (18+22=40) and adding the result to the "Composite Worst-Case Unit Accumulation."

[7] The "Projected to 60 years" column was calculated by multiplying the "Accumulation Rate" value by 42 years (18+42=60) and adding the result to the "Composite Worst-Case Unit Accumulation."

[8] The "(1985-1995) 25% Assumed" column lists the 25% assumed accumulations ~~initally~~ initially recorded in Appendix K of the 1995 record of the cycle count procedure.

[9] Transients not counted in the APS fatigue cycle count verification are marked as "NC."

[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 APS recount included all occurrences from 1985-2005. The "Accumulation Rate" was calculated by taking the APS recount number and dividing by the least number of years in operation up to ~~1995~~2005 (Unit 3 operating period of 18 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 th~~e Fatigue Management Program~~ APS recount. 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 Transients 16, 17, 24, 26, 36, 40, ~~and~~ 50, 60, and 61. 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 by the Fatigue Management Program software because it is ~~included in~~ the sum of 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~~1985-2005 include 64 cycles of this transient for Unit 1, ~~0~~1 cycle~~s~~ 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.~~
[27] Transient 21, "Auxiliary Spray During Cooldown," occurs during each occurrence of Transient 12, "Pressurizer Cooldown."

Source: RAI B3.1-3 Response

LRA Section 4.3.1.5, Program Scope, Action Limits, and Corrective Actions (page 4.3-22), "Scope," paragraph 3, is revised to read (incorrect text is struck out, new text is underlined):

"The "Fatigue Management Method" column of Table 4.3-4 indicates the method ~~FatiguePro®~~ the automated software will use...."

LRA Section 4.3.1.5, *Cumulative Fatigue Usage Action Limits and Corrective Actions* (page 4.3-24), paragraph 1, is revised to read (incorrect text is struck out, new text is underlined):

"The ~~FatiguePro® program~~ automated three-dimensional, six-element, stress-based fatigue management program module (the SBF module, meeting ASME III NB-3200 requirements) will continually monitor cumulative usage factor (CUF) at the...."

LRA Table 4.3-4, Summary of Fatigue Usage from Class 1 Analyses and Method of Management by the PVNGS Fatigue Management Program (page 4.3-29), Endnote 5 is revised to read (incorrect text is struck out, new text is underlined):

"5 Fatigue in these external lugs is fully bounded by fatigue in the RPV head studs, which ~~is~~ will be monitored by FatiguePro®.
The design CUF for the studs...."

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 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 1014986, "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, and EPRI 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.

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.
- 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, 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

to selective leaching is occurring. If indications of selective leaching are confirmed, follow up examinations or evaluations are performed.

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, 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.

For 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. <u>If no socket welds are in the sample population, then at least one weld per unit will be selected. A different socket weld location will be selected for each unit.</u>

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 this will be used for the volumetric examinations ~~will be conducted on small-bore socket welds as part of the PVNGS program~~. If no volumetric examination procedure for ASME Code Class 1 small bore socket welds has been endorsed by the industry and the NRC and incorporated into ASME Section XI at the time PVNGS performs inspections of small-bore piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

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 and Radiation Monitoring Systems including the source range, intermediate range, ~~and~~ power range monitors, and non-EQ area radiation 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 for non-EQ area radiation monitors 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.

Cable testing will be used to manage the aging of the cable insulation and connections for the ex-core neutron monitoring system. Cable tests such as insulation resistance testing or other tests will be performed to detect deterioration of the cable insulation system. The cable will be tested prior to the period of extended operation and every 10 years thereafter. Acceptance criteria will be determined prior to testing based on the type of cable and type of test performed.

Prior to the period of extended operation, procedures will be enhanced to identify license renewal scope, require cable testing of ex-core neutron monitoring cables, ~~and~~ require an evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on type of cable and type of test performed.

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 (moisture that lasts more than a few days) simultaneously with significant voltage (energized greater than 25% of the time) 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. Collected water will be removed as required. This inspection and water removal will be performed based on actual plant experience with water accumulation in the manhole with an inspection frequency of at least every two years.

The program provides for testing of in-scope non-EQ inaccessible medium voltage cables to provide an indication of the conductor insulation condition. At least once every ten years, a polarization index test as described in EPRI TR-103834-P1-2 or other testing that is state-of-the-art at the time of the testing is performed.

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.

A1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE containment inservice inspection program manages loss of material and loss of sealing of the steel liner of the concrete containment building, including the containment liner plate, piping and electrical penetrations, access hatches, and the fuel transfer tube. Inspections are performed to identify and manage any containment liner aging effects that could result in loss of intended function. Acceptance criteria for components subject to Subsection IWE exam requirements are specified in Article IWE-3000. In conformance with 10 CFR 50.55a(g)(4)(ii), the PVNGS CISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

A1.28 ASME SECTION XI, SUBSECTION IWL

The ASME Section XI, Subsection IWL program manages cracking, loss of material, and increase in porosity and permeability of the concrete containment building and post-tensioned system. Inspections are performed to identify and manage any aging effects of the containment concrete, post-tensioned tendons, tendon anchorages, and concrete surface around the anchorage that could result in loss of intended function. In conformance with 10 CFR 50.55a(g)(4)(ii), the ASME Section XI, Subsection IWL Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

A1.32 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program manages the cracking, loss of material, and change in material properties by monitoring the condition of structures and structural supports that are within the scope of license renewal. The Structures Monitoring Program implements the requirements of 10 CFR 50.65 and is consistent with the guidance of NUMARC 93-01, Revision 2 and Regulatory Guide 1.160, Revision 2.

The Structures Monitoring Program provides inspection guidelines for concrete elements, structural steel, masonry walls, structural features (e.g., caulking, sealants, roofs, etc.), structural supports, and miscellaneous components such as doors. The Structures Monitoring Program includes all masonry walls and water-control structures within the scope of license renewal. The Structures Monitoring Program also monitors settlement for each major structure and inspects supports for equipment, piping, conduit, cable tray, HVAC, and instrument components.

Prior to the period of extended operation:

<u>The Structures Monitoring Program will be enhanced to define the specific criteria for categorizing deficiencies for concrete inspections.</u>

The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program.

A2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

A2.1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

The Metal Fatigue of Reactor Coolant Pressure Boundary program will ensure that actual plant experience remains bounded by the assumptions used in the design calculations, or that appropriate corrective measures maintain the design and licensing basis by other acceptable means. Most Class 1 location cumulative usage factor (CUF) estimates support the supposition that the number of transient cycles expected in a 60-year life will not produce fatigue usage factors significantly in excess of those calculated by the analyses that assumed a 40-year life; and should produce none exceeding the code limit of 1.0. Estimates of the effects of the reactor coolant environment as described by NUREG/CR-6260 indicate that CUF in some of these affected locations may however, exceed 1.0. The Metal Fatigue of Reactor Coolant Pressure Boundary program will track the number of transient cycles and cumulative fatigue. If cycle counts or CUF values increase to the program action limits, corrective actions will be initiated to evaluate the design limits and determine appropriate specific corrective actions. Action limits permit completion of corrective actions before the design basis number of events is exceeded.

No later than two years p~~P~~rior to the period of extended operation, the following enhancements will be implemented:

The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include: (1) additional Class 1 locations with high calculated CUFs, (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 CUFs.

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.

2) 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.

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.

The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. A fatigue monitoring software program that incorporates a three-dimensional, six-element model meeting ASME III NB-3200 requirements will be used for stress-based fatigue monitoring (SBF).

A2.2 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

The Environmental Qualification (EQ) of Electrical Components program manages component thermal, radiation, and cyclic aging effects, using 10 CFR 50.49(f) methods. As required by 10 CFR 50.49, EQ components are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Maintaining qualification through the extended license renewal period requires that existing EQ evaluations (EEQDFs) be re-evaluated. The Environmental Qualification (EQ) of Electrical Components program is consistent with the guidance of 10 CFR 50.49, NUREG-0588, and Regulatory Guide 1.89, "*Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants*", Revision 1 for maintaining qualifications of equipment. Reanalysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the EQ Program. Important attributes for the reanalysis of aging evaluations include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

A3.2.4 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ANSI B31.1 and ASME Section III Class 2 and 3 Piping

PVNGS ASME III Class 2 and 3 piping is designed to the 1974 edition, Summer 1975 addenda; plus later editions and addenda for certain requirements. None of ANSI B31.1 or ASME Section III Subsections NC and ND invokes fatigue analyses. However, if the number of full-range thermal cycles is expected to exceed 7,000, these codes require the application of a stress range reduction factor (SRRF) to the allowable stress range for expansion stresses (secondary stresses). The allowable secondary stress range is 1.0 S_A for 7000 equivalent full-temperature thermal cycles or less and is reduced in steps to 0.5 S_A for greater than 100,000 cycles. Partial cycles are counted proportional to their temperature range. Therefore, so long as the estimated number of cycles remains less than 7000 for a 60-year life, the stress range reduction factor remains at 1 and the stress range reduction factor used in the piping analysis will not be affected by extending the operation period to 60 years.

The survey of all plant piping systems found that the reactor coolant hot leg sample lines may be subject to more than 7000 significant thermal cycles in 60 years, requiring a reduction in SRRF to 0.9; and that the steam generator downcomer and feedwater recirculation lines may be subject to more than 15,000, requiring a reduction in SRRF to 0.8. The applicable PVNGS design analyses were revised, and found that the secondary stress ranges are within the limits imposed by these reduced SRRFs. The pipe break analysis included in the revised analysis of the steam generator downcomer and feedwater recirculation lines required no change to break locations or break types. These analyses have therefore been extended to the end of the period of extended operation.

The number of equivalent full-range thermal cycles for all other B31.1 and ASME III Class 2 and 3 lines within the scope of license renewal is expected to be only about 1500 or less in 60 years, which is only a fraction of the 7000-cycle threshold for which a stress range reduction factor is required in the applicable piping codes. The piping analyses for these remaining lines therefore require no change to the SRRF of 1.0 and remain valid for the period of extended operation.

A3.3 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

Aging evaluations that qualify electrical and I&C components required to meet the requirements of 10 CFR 50.49 are evaluated to demonstrate qualification for the 40 year plant life are TLAAs. The existing PVNGS Environmental Qualification program will adequately manage component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be

refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Continuing the existing 10 CFR 50.49 EQ program ensures that the aging effects will be managed and that the EQ components will continue to perform their intended functions for the period of extended operation. The Environmental Qualification of Electrical Components program is described in Section A2.2.

Reanalysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the EQ Program. Important attributes for the reanalysis of aging evaluations include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

A3.4 CONCRETE CONTAINMENT TENDON PRESTRESS

The PVNGS containment is a prestressed concrete, hemispherical-dome-on-a-cylinder structure, with a steel membrane liner. Post-tensioned tendons compress the concrete and permit the structure to withstand design basis accident internal pressures. The reinforced concrete basemat is conventionally reinforced.

To ensure the integrity of the containment pressure boundary under design basis accident loads, design predictions of loss of prestress demonstrate that prestress will remain adequate for the design life. An inspection program confirms that the tendon prestress remains within design limits throughout the life of the plant [UFSAR Section 3.8.1, Technical Specification Surveillance Requirement 3.6.200.1].

Original design predictions of prestress force were projected to the end of the period of extended operation. The extended predicted force lines remain above minimum required values (MRVs) for the period of extended operation. Trend lines calculated by regression analyses of tendon surveillance data to date predict that the future performance of the post-tensioning system will remain above the minimum required values (MRV), and therefore that the assumptions of the containment vessel design will remain valid through the end of the period of extended operation.

Continuing the existing Concrete Containment Tendon Prestress program (A2.3) ensures that loss of prestress aging effects will be managed and that the containment tendons will continue to perform their intended functions for the period of extended operation.

A3.5 CONTAINMENT LINER PLATE, EQUIPMENT HATCHES, PERSONNEL AIR LOCKS, PENETRATIONS, AND POLAR CRANE BRACKETS

NUREG-1800 Section 4.6.1 notes that in some designs "Fatigue of the liner plates or metal containments may be considered in the design based on an assumed number of loading cycles for the current operating term".

The PVNGS post-tensioned concrete containment vessels are designed to Bechtel Topical Report BC-TOP-5-A Revision 3. The containment design report has been revised to address effects of power uprate and steam generator replacement.

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
1	Section A3 [of the LRA] contains evaluation summaries of TLAAs for the period of extended operation. These summary descriptions of aging management program programs and time-limited aging analyses will be incorporated in the Updated Final Safety Analysis Report for PVNGS following issuance of the renewed operating license in accordance with 10 CFR 50.71(e). (RCTSAI 3247244)	A0	The next 10 CFR 50.71(e) UFSAR update following issuance of the renewed operating license. (Estimated June 30, 2011)
2	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. (RCTSAI 3246887)	A1 B1.3 Summary Descriptions Of Aging Management	Prior to the period of extended operation[1].
3	Existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is credited for license renewal. (RCTSAI 3246890)	A1.1 B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, AND IWD	Ongoing
4	Existing Water Chemistry program is credited for license renewal~~, AND 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 nonpurgeable Organic Carbon~~. (RCTSAI 3246891).	A1.2 B2.1.2 Water Chemistry	~~Prior to the period of extended operation[1].~~ Ongoing
5	Existing Reactor Head Closure Studs program is credited for license renewal. (RCTSAI 3246892)	A1.3 B2.1.3 Reactor Head Closure Studs	Ongoing
6	Existing Boric Acid Corrosion program is credited for license renewal. (RCTSAI 3246893)	A1.4 B2.1.4 Boric Acid Corrosion	Ongoing

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
15	Existing Fire Water System program is credited for license renewal, AND 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 to state trending requirements. **(Completed)** • 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). **(Completed)** (RCTSAI 3246902)	A1.13 B2.1.13 Fire Water System	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, require cable testing of ex-core neutron monitoring cables, ~~and~~ require an evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on the type of cable and type of test performed. • 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
34	Existing Structures Monitoring Program is credited for license renewal, AND Prior to the period of extended operation: • The Structures Monitoring Program will be enhanced to define the specific criteria for categorizing deficiencies for concrete inspections. • The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program. (RCTSAI 3246927)	A1.32 B2.1.32 Structures Monitoring Program	Prior to the period of extended operation[1].

Source: RAI B3.1-3 and RAI B3.1-8 Responses

LRA Table A4-1 Commitment 39, page A-54, is revised to read (incorrect text is struck out, new text is underlined):

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
39	(1) The existing Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to provide guidelines and requirements for tracking both transient cycle counts and fatigue usage of selected ~~fatigue-sensitive, safety related~~ components, using ~~the~~ FatiguePro® software, to maintain the fatigue usage factor of these components less than ~~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 plant cycle ~~FatiguePro®~~ data, and review of the resulting usage factor data. (2) ~~Prior to the period of extended operation, the following enhancements will be implemented:~~The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. A fatigue monitoring software program that incorporates a three-dimensional, six-element model meeting ASME III NB-3200 requirements will be used for stress-based fatigue monitoring (SBF).	4.3.1 Fatigue Aging Management Program A2.1 B3.1 Metal Fatigue of Reactor Coolant Pressure Boundary A3.2 Metal Fatigue Analysis	No later than two years ~~P~~prior to the period of extended operation[1].

Item No.	Commitment	LRA Section	Implementation Schedule
	•—(3) 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. The specific locations are listed in Table 4.3-4, "Summary of Fatigue Usage from Class 1 Analyses, and Method of Management by the Metal Fatigue of Reactor Coolant Pressure Boundary Program." •—(4) The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced with additional cycle count and fatigue usage action limits including appropriate corrective actions to be invoked if a component approaches a cycle count action limit or a fatigue usage action limit. Action limits shall be chosen with the intent that they will permit completion of corrective actions before the design limits are exceeded. (RCTSAI 3246934)		

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
40	Existing Environmental Qualification program is credited for license renewal, AND ~~M~~maintaining qualification through the extended license renewal period requires that existing EQ evaluations (EEQDFs) be re-evaluated. (RCTSAI 3246935)	A2.2 B3.2 Environmental Qualification (EQ) Of Electrical Components	Prior to the period of extended operation[1].
41	Existing Concrete Containment Tendon Prestress program is credited for license renewal, AND The program will be enhanced to continue to compare regression analysis trend lines of the individual lift-off values of tendons surveyed to date, in each of the vertical and hoop tendon groups, with the MRV and PLL for each tendon group, to the end of the licensed operating period, and to take appropriate corrective actions if future values indicated by the regression analysis trend line drop below the PLL or MRV. The regression analyses will be updated for tendons of the affected unit and for a combined data set of all three units following each inspection of an individual unit. Prior to the period of extended operation, procedures will be enhanced to require an update of the regression analysis for each tendon group of each unit, and of the joint regression of data from all three units, after every tendon surveillance. The documents will invoke and describe regression analysis methods used to construct the lift-off trend lines, including the use of individual tendon data in accordance with Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The Tendon Integrity test procedure will be revised to extend the list of surveillance tendons to include random samples for the year 45 and 55 surveillances. (RCTSAI 3246937)	A2.3 B3.3 Concrete Containment Tendon Prestress 4.5 Concrete Containment Tendon Prestress	Prior to the period of extended operation[1].

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. 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 105714 "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, both Revision 6 (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 102134, "*PWR Secondary Water Chemistry Guidelines*", Revision 7 (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 1014986, Volumes 1 and 2, Revision 6, for primary water chemistry and EPRI 1016555, Revision 7, for secondary water chemistry. The Revision 6 changes to EPRI 1014986 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

None

~~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.

B2.1.7 Bolting Integrity

Program Description

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 preload control, selection of bolting material, use of lubricants/sealants consistent with EPRI good bolting practices, and performance of periodic inspections for indication of aging effects. The program is supplemented by Inservice Inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

PVNGS good bolting practices are established in accordance with plant procedures. These procedures include requirements for proper disassembling, inspecting, and assembling of connections with threaded fasteners. The general practices that are established in this program are consistent with EPRI NP-5067, "*Good Bolting Practices, Volume 1 and Volume 2*", and the recommendations delineated in NUREG-1339.

Following the review of the recommendations provided in NRC Generic Letter 91-17, NUREG-1339 and the EPRI reports, NP-5769 and NP5067, PVNGS had identified and implemented the action items related to bolting degradation or failure. The guidance provided in EPRI NP-5067 and NUREG-1339, together with other industrial experience regarding bolting issues was later consolidated in EPRI TR-104213, "*Bolted Joint Maintenance and Applications Guide*". Although the procedures for ensuring bolting integrity do not directly reference EPRI reports NP-5769 and TR-104213 or NUREG-1339 as applicable source documents for these recommendations, these procedures do incorporate the action items to ensure the integrity of the subject bolting connections.

The following PVNGS aging management programs supplement the Bolting Integrity program for management of loss of preload, cracking, and loss of material:

(a) ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD program (B2.1.1), provides the requirements for inservice inspection of ASME Class 1, 2, and 3 safety-related pressure retaining bolting.

(b) ASME Section XI, Subsection IWF program (B2.1.29), provides the requirements for inservice inspection of safety-related component support bolting.

(c) External Surfaces Monitoring Program (B2.1.20) provides the requirements for inspection of pressure retaining closure bolting within the scope of license renewal.

NUREG-1801 Consistency

The Bolting Integrity program is an existing program that is consistent, with exception to NUREG-1801, Section XI.M18, "Bolting Integrity".

Exceptions to NUREG-1801

Program Elements Affected

Scope of Program – Element 1

NUREG 1801, Section XI.M18 specifies the use of ASME Section XI 1995 edition with addenda 1996. PVNGS third interval ISI Program is using 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 will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation.

Parameters Monitored or Inspected – Element 3

Loss of preload is not a parameter of inspection for the PVNGS Bolting Integrity Program. The discussion of bolt preload in EPRI NP-5769, Vol. 2, Section 10, indicates that job inspection torque is non-conservative since for a given fastener tension more torque is required to restart the installed bolts. The techniques for measuring the amount of bolt tension in an assembled joint are both difficult and unreliable. EPRI NP-5769, Vol. 2, Section 10 suggests that inspection of preload is usually unnecessary if the installation method has been carefully followed. Torque values are provided in procedures, if not provided by the vendor instructions, design documents or specifications. The torque values provided in procedures are based on the industrial experience that includes the consideration of the expected relaxation of the fasteners over the life of the joint and gasket stress in the application of pressure closure bolting.

Monitoring and Trending –Element 5

NUREG 1801, Section XI.M18 specifies that if bolting connections for pressure retaining components (not covered by ASME Section XI) are reported to be leaking, then they may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly. For pressure retaining components reported to be leaking, the corrective action program will be initiated. The corrective actions, including adjustment of the inspection frequency for closer monitoring of the condition if necessary, will be identified based on the analysis of the trending data to ensure there is not a loss of intended function of the subject components. For the components that are deemed necessary, preventive maintenance activities, such as gasket replacement or bolting tightness check, can be created.

Enhancements

None

Operating Experience

Both the industry and NRC have revealed a number of instances of bolting concerns from material control and certification (e.g. NRC IE Bulletin 87-02) to bolting practices, use of lubrication and injection sealants and its effect on stress corrosion cracking (SCC) (e.g., NRC IE Bulletin 82-02, and INPO SOER 84-05). The Bolting Integrity program incorporates the applicable industry experience on bolting issues into the program. Actions taken include confirmatory testing/analysis or inspections. Also included are the addition of procedures of inspection, material procurement and verification processes. NRC Information Notices, Bulletins, Circulars, and Generic Letters listed in Section 3 of NUREG-1339 were evaluated for applicability to PVNGS Bolting Integrity program to ensure conformance with the recommendations of NUREG-1339.

A review of plant operating experience identified issues with corrosion, missing or loose bolts, inadequate thread engagement, and improper bolt applications. There is no reported case of cracking of the bolts due to stress corrosion cracking. In all cases, the identified concern was corrected or evaluated to be accepted as-is. No significant safety events were identified. Additional actions, such as procedural enhancements, were implemented as needed to prevent recurrence.

Conclusion

The continued implementation of Bolting 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.

B2.1.10 Closed-Cycle Cooling Water System

Program Description

The Closed-Cycle Cooling Water (CCCW) System program manages loss of material, cracking, and reduction in heat transfer for components in the following closed cycle cooling water systems:

- Diesel Generator Jacket Water System
- Essential Chilled Water System
- Essential Cooling Water System
- Normal Chilled Water System
- Nuclear Cooling Water System

The CCCW systems serve heat exchangers and related components that are within the scope of license renewal in the following interfacing systems:

- Auxiliary Steam System
- Chemical and Volume Control System
- Spent Fuel Pool Cooling and Clean Up System
- Reactor Coolant System
- Secondary Chemical Control System
- Safety Injection and Shutdown Cooling System
- Nuclear Sampling System
- Auxiliary Building HVAC
- Containment Building HVAC
- Control Building HVAC

The program includes (a) maintenance of system corrosion inhibitor concentrations to minimize aging effects and (b) periodic testing and inspections to evaluate system and component performance. The water chemistry aspect of the program maintains an environment within CCCW systems that is consistent with the parameters specified in EPRI TR-107396 for CCCW system. Water chemistry is maintained through the addition of an

iron corrosion inhibitor (nitrite), a copper corrosion inhibitor (tolyltriazole - TTA), pH control and biocide (glutaraldehyde). System corrosion inhibitor concentrations are maintained at levels described in EPRI TR-107396 to minimize aging effects. Testing and inspections are performed in accordance with guidance in EPRI TR 107396 for closed-cycle cooling water (CCCW) systems as appropriate for their license renewal intended functions; for example, components ~~in scope of license renewal for criterion a(2) considerations only are not subject to internal inspection or performance testing.~~ which do not have a license renewal heat transfer function, but which are evaluated as having a license renewal intended function of pressure boundary or leakage barrier are not subject to internal inspection or performance testing. The effectiveness of water chemistry control measures of these heat exchangers is verified by visual inspection of the internal surfaces of selected components fabricated of similar materials and exposed to closed-cycle water using the same corrosion inhibitor program. Inspection processes include visual, eddy-current and ultrasonic methods. Testing methods include functional demonstrations and monitoring, thermal and hydraulic performance testing.

NUREG-1801 Consistency

The Closed-Cycle Cooling Water System program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.M21, "Closed-Cycle Cooling Water."

Exceptions to NUREG-1801

Program Elements Affected

Preventive Actions - Element 2

NUREG-1801, Section XI.M21, Element 2, requires materials used in CCCW systems to be appropriate to the type of service. The essential cooling water system for each unit is provided with two radiation monitors (one per train) that employ an aluminum "window" as a pressure boundary between the CCCW and the ionization detector within the flow-through sample chambers. The chemical treatment program at PVNGS does not include controls described in EPRI TR-107396 as appropriate for aluminum. Exception is taken to employ the NUREG 1801 AMP XI.M38 Internal Surfaces Monitoring Program to manage the aging of the aluminum "windows" of the radiation monitors. A review of plant operating experience reveals no instances where aging effects have led to the loss of the intended function of the subject components.

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

NUREG-1801, Section XI.M21, Element 3 requires testing and inspection as described in EPRI TR-107396 and further states "For pumps, the parameters monitored include flow, discharge pressures, and suction pressures and for heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure" and Element 5 states "visual inspections and performance/functional tests are to be performed to confirm the effectiveness of the program." PVNGS monitors system parameters and performs a combination of visual inspections, non-destructive evaluations, performance and functional

tests as well as thermal performance tests as described in EPRI TR-107396 Section 8.4 to confirm the effectiveness of the CCCW program in managing the aging of components and systems exposed to CCCW. Plant configuration constraints and consideration of components ~~in-scope of license renewal for 10CFR54.4 criterion a(2) considerations only~~ which do not have a license renewal heat transfer function, but which are evaluated as having a license renewal intended function of pressure boundary or leakage barrier have led to several exceptions with respect to some measures set forth in NUREG-1801 with respect to testing and inspection specifics that together do not compromise the ability to monitor program effectiveness to ensure the component intended functions are maintained. Specific exceptions taken include:

a.) The essential cooling water, spent fuel cooling and cleanup, and shutdown cooling heat exchangers are not monitored for differential pressure. The program of periodic sampling and maintenance of system chemistry together with thermal performance testing in conformance with EPRI NR-7552, and, in the case of the essential cooling water heat exchanger, periodic ECT of the heat exchanger tubes and, in the case of the spent fuel cooling and cleanup heat exchanger, periodic NDE of the heat exchanger shell are adequate to ensure that component intended functions of pressure boundary and heat transfer are maintained.

b.) The essential chilled water and essential cooling water system circulating water pumps are not subject to periodic internal visual inspection or casing NDE. These pumps are monitored for flow, suction pressure and discharge pressure in accordance with the approved ASME Pump and Valve In-Service Testing Program. The performance monitoring of these pumps together with periodic sampling and control of water chemistry is adequate to ensure component intended function is maintained.

c.) The essential chilled water system chiller condenser, water cooler and lube oil cooler are not individually monitored for flow, inlet and outlet temperatures, and differential pressure. During periodic surveillance testing, the heat load on the essential chilled water system is not reproducible from test-to-test. Plant procedures require that these components are subject to visual inspection when their respective chiller is rebuilt. Visual inspection together with the periodic sampling and control of system water chemistry is adequate to ensure the component intended functions are maintained.

d.) The individual ventilation cooling coils served by the essential chilled water system are not monitored for differential pressure and, additionally are not subject to visual inspection of their internal surfaces or NDE because the internal diameter and geometry of the coils preclude effective internal inspection. The combination of chemistry control, preventive maintenance, air side inspection, and testing of a control room air filtration unit in each train provides reasonable assurance that essential auxiliary building HVAC and control building HVAC system cooling coil performance has not degraded. A review of plant operating experience reveals no instances where aging effects have led to the loss of the intended function of the subject components.

e.) The diesel generator jacket water engine-driven circulating water pump, the motor-driven circulating water pump, the jacket water heat exchanger, turbo air intercooler, turbocharger and governor lube oil cooler are not individually monitored for flow, inlet and outlet

temperatures, and differential pressure and internal visual inspections are not performed on each component. At PVNGS, diesel generator performance parameters are monitored through periodic Technical Specification surveillance tests. Plant procedures require temperature and pressure parameters be compared to pre-established limiting values. From the comparison, overall heat exchanger and pump performance can be inferred collectively for the diesel generator under test. With respect to the motor-driven circulating water pump, the pump operates cyclically together with a heater to maintain jacket water temperature when the diesel generator is in standby; its functional performance is continuously monitored by measuring jacket water temperature. The diesel generator governor oil cooler, the engine-driven and motor-driven circulating water pumps and the turbocharger are not individually subject to periodic visual inspection. The jacket water heat exchanger and the turbo air intercooler are periodically inspected visually as an indication of interior surface conditions throughout the diesel generator jacket water system. The surveillance tests together with periodic visual inspections and the periodic sampling and control of system water chemistry are adequate to ensure the component intended functions are maintained within the diesel generator jacket water system.

f.) The RC hot leg sample cooler is within scope of license renewal for 10CFR54.4 criteria a(3) fire protection considerations that identify the capability to obtain a RC hot leg sample for boron concentration as a means of reactivity control. Exception is taken for regular, periodic inspection and testing of this heat exchanger based on its variable heat load and on ~~its frequent use in normal operations that would permit identification of any abnormality in obtaining a sample. The periodic sampling and maintenance of system chemistry together with operator observation of component performance in service is adequate to ensure the component intended function of pressure boundary and heat transfer are maintained for the RC hot leg sample cooler.~~ the fact that the design configuration of the RC hot leg sample cooler is a sealed unit not subject to opening for routine inspection or maintenance. The effectiveness of water chemistry control measures for this heat exchanger is verified by visual inspection of the internal surfaces of selected components fabricated of similar materials and exposed to closed-cycle cooling water using the same corrosion inhibitor program.

g.) Several heat exchangers are provided which do not have a license renewal heat transfer intended function and are not monitored for parameters pertaining to heat transfer nor subject to periodic performance monitoring and inspection to manage the aging effect of reduction in heat transfer. These heat exchangers include the letdown heat exchanger, which has the intended function of pressure boundary, and the following heat exchangers, which have the intended function of leakage barrier - spatial:

- auxiliary steam vent condenser
- cooler for auxiliary steam radiation monitor
- cooling coils for normal HVAC Units (containment, auxiliary, and control building HVAC).
- steam generator hot leg, cold leg and downcomer blowdown sample coolers

- pressurizer steam space and surge line sample coolers
- safety injection sample coolers

~~For these heat exchangers, the periodic sampling and maintenance of system chemistry is adequate to ensure the component intended function is maintained.~~ The effectiveness of water chemistry control measures for these heat exchangers is verified by visual inspection of the internal surfaces of selected components fabricated of similar materials and exposed to closed-cycle cooling water using the same corrosion inhibitor program.

Enhancements

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

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

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.

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

Procedures will be enhanced to clarify and expand the scope of inspections and tests and to add implementing references for additional NDE methods to align with EPRI TR-107396 Section 8.4. Additionally, a procedure will be added as an implementing reference to further define heat exchanger performance testing for essential (safety-related) cooling coils.

Acceptance Criteria – Element 6

Procedures will be enhanced to more clearly define the acceptance criteria for visual inspection for "cracks" to include indications of stress corrosion cracking and to update implementing references.

Operating Experience

A review of the PVNGS plant-specific operating experience indicates that there has been no evidence of significant fouling or loss of material that has resulted in a loss of intended function observed in the following closed cycle cooling systems:

- Diesel Generator Jacket Water System
- Essential Chilled Water System
- Essential Cooling Water System
- Normal Chilled Water System

- Nuclear Cooling Water System

During the second half of 2001, water chemistry monitoring identified an elevated levels of chlorides and sulfates characteristic of leakage from the essential spray pond system into the essential cooling water system of Unit 3. Diagnostic water chemistry testing further localized the source of the leak to the B-train essential cooling water heat exchanger. Visual inspection and Non-Destructive Evaluation (eddy current testing) were performed and localized the leak to a heat exchanger tube which was subsequently plugged. The cause was evaluated as a pit resulting from corrosion from the open-cycle cooling side of the heat exchanger into the closed-cycle side of the heat exchanger. An expanded testing program encompassing 100% of the essential cooling water heat exchanger tubes in all three units revealed no further degradation. This event demonstrates the effectiveness of managing the aging of the closed-cycle cooling water systems.

Conclusion

The continued implementation of the Closed-Cycle Cooling Water 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.

B2.1.13 Fire Water System

Program Description

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 in accordance with National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended function. The fire water system pressure is continuously monitored such that loss of system pressure is immediately detected and corrective actions initiated.

The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for over 50 years, using the guidance of the current code of record or NFPA 25, 2002 Edition, and will test at 10-year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion will be done through the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22). Buried Piping and Tanks Inspection program (B2.1.18) is credited with the management of aging effects on the external surface of buried fire water system piping.

NUREG-1801 Consistency

The Fire Water System program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.27, "Fire Water System".

Exceptions to NUREG-1801

Program Elements Affected

Detection of Aging Effects – Element 4

PVNGS performs power block hose station gasket inspections once per 18 months as opposed to once per 12 months. Technical Requirements Manual Surveillance Requirement (TSR) 3.11.104.4 states the inspection frequency to be 18 months.

PVNGS performs hydrostatic testing on fire hoses once per three years. Replacement fire hoses that have been hydrostatically tested are available if needed in lieu of performing a hydrostatic test. TSR 3.11.104.6 states the inspection frequency to be 3 years.

Enhancements

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

Preventive Actions - Element 2 and Acceptance Criteria – Element 6

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

Parameters Monitored or Inspected – Element 3

Procedures will be enhanced to be consistent with the current code of record or NFPA 25, 2002 Edition.

Detection of Aging Effects – Element 4

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.

~~*Corrective Actions – Element 7*~~

~~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).~~

Operating Experience

NaOH and NaSO3 are added to the fire water system and sampled periodically. Based on analyses of corrosion coupons, the corrosion rate has been 0.3 mils/yr thus indicating successful corrosion control measures.

There has been some at-grade evidence of buried piping leakage observed. Remote field eddy current testing was performed on about 7,721 feet of 12-inch pipe covering the fire water main loop. Test results indicated that there were several sections of pipe that had localized degradation in excess of the minimum wall thickness of 40% of nominal wall thickness. Validation was then performed by excavating and removing two spools, and corrosion related pitting was confirmed. PVNGS replaced portions of the North and South Loop piping with epoxy lined reinforced fiberglass. Replacement of approximately 6,000 feet of pipe on the North Loop was completed during September of 2001. Approximately 4,500 feet of pipe on the South Loop was completed during July of 2006. Some of this degradation was attributed to coating holidays caused by improper backfilling and lack of cathodic protection attention during early plant operation.

The flushes of the deluge system, fire hydrants, and underground fire water loops have identified little or no debris in the lines, and there have been no indications that the SSCs would not be able to perform their intended function.

A review of the past ten years of corrective action documents showed no signs of gasket degradation or fire hose degradation due to inspection intervals of 18 months and three years, respectively.

Conclusion

The continued implementation of the Fire 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.

B2.1.19 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.

For ASME Code Class 1 small-bore piping, 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. If no socket welds are in the sample population, then at least one weld per unit will be selected. A different socket weld location will be selected for each unit.

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 this will be used for the volumetric examinations ~~will be conducted on small-bore socket welds as part of the PVNGS program~~. If no volumetric examination procedure for ASME Code Class 1 small bore socket welds has been endorsed by the industry and the NRC and incorporated into ASME Section XI at the time PVNGS performs inspections of small-bore piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

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.

NUREG-1801 Consistency

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program 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

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 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.

B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages embrittlement, melting, cracking, swelling, surface contamination, or discoloration to ensure that electrical cables, connections and terminal blocks 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 functions.

Technical information contained within SAND96-0344 and EPRI TR-1003057 was used to determine the service limitations of the cable, connection and terminal block insulating materials. SAND96-0344 and EPRI TR-109619 provided guidance on techniques for visually inspecting cables, connections and terminal blocks for aging.

Non-EQ cables, connection and terminal blocks within the scope of license renewal in accessible areas with an adverse localized environment are inspected. Connection insulation material includes termination kits and tape used to insulate splices that are normally located within junction boxes, terminal blocks located within terminal boxes, and non-EQ electrical containment penetrations. The inspections of Non-EQ cables, connectors and terminal blocks in accessible areas are representative, with reasonable assurance, of cables, connections and terminal blocks in inaccessible areas with an adverse localized environment. At least once every ten years, the Non-EQ cables, connections and terminal blocks within the scope of license renewal in accessible areas are visually inspected for embrittlement, melting, cracking, swelling, surface contamination, or discoloration.

The acceptance criterion for visual inspection of accessible Non-EQ cable jacket, connection terminal block insulating material is the absence of anomalous indications that are signs of degradation. 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.

A new procedure will implement the aging management program and provide for the identification of adverse localized environments.

NUREG-1801 Consistency

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program.

Industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indications of degradation.

A review of the plant operating history found three minor cases of cable aging due to adverse environments.

A lighting power cable with degraded insulation was found. The cause was indeterminate and cable was replaced. In the second case, conduits were run too close to a steam line. The conduits were relocated and the cables meggered. No cable degradation was found. In the third case, water was found leaking from a pull box. The cable was abandoned and conduit was sealed.

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

Conclusion

The implementation of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that adverse localized environments are identified and 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 and area radiation monitoring systems. 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 are used to manage the aging of the cable insulation and connections for non-EQ area radiation monitors 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.

Cable testing will be used to manage the aging of the cable insulation and connections for the ex-core neutron monitoring system. Cable tests such as insulation resistance testing or other tests will be performed to detect deterioration of the cable insulation system. The cable will be tested prior to the period of extended operation and every 10 years thereafter. Acceptance criteria will be determined prior to testing based on the type of cable and type of test performed.

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~~ Parameters Monitored or Inspected – Element 3, Detection of Aging Effects - Element 4, Acceptance Criteria – Element 6, and Corrective Actions – Element 7.

Procedures will be enhanced to identify license renewal scope, ~~and~~ require cable testing of ex-core neutron monitoring cables, require an evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on the type of cable and type of test performed.

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 (moisture that lasts more than a few days) simultaneously with significant voltage (energized greater than 25% of the time) 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 of 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.~~ In all cases the splices were reworked. In addition, in one case the splice was moved to a manhole less subject to water intrusion.

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. When a manhole is found to contain water, the frequency of inspection is changed to six months and the manhole is added to a "rain PM." The manhole is inspected any time there is a rain accumulation of greater than 3 inches in 24 hours and every six months until it has been found dry for two years. Manhole inspection frequency has been changed from a maximum five year interval to two years maximum. ~~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 with submerged cables has had a seal replaced, lid raised above grade, and the ground surface reworked to route water away from the manhole ~~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.

B2.1.28 ASME Section XI, Subsection IWL

Program Description

The ASME Section XI, Subsection IWL program manages cracking, loss of material, and increase in porosity and permeability of the concrete containment building and post-tensioned system. Included in this inspection program are the concrete containment structure (includes all accessible areas of the concrete dome, cylinder walls, and buttresses), and the post-tensioning system (includes tendons, end anchorages, and concrete surfaces around the end anchorages). Concrete surface areas are visually examined for indications of distress or deterioration such as those defined in ACI201.1R-92. Tendon prestress forces are measured by lift-off, and tendon wires are examined for corrosion or mechanical damage. The yield strength, ultimate tensile strength, and elongation are recorded. Grease caps are examined for grease leakage or grease cap deformation. Grease samples are analyzed in accordance with Table IWL-2525-1. For the inspection interval from August 1, 2001 to July 31, 2011, PVNGS performs IWL Inservice Inspections in accordance with the 1992 Edition of ASME Section XI (with 1992 Addendum), Subsection IWL, supplemented with the applicable requirements of 10 CFR 50.55a(b)(2) and additional commitments. The PVNGS IWL ISI program is consistent with the 2001 edition of ASME Section XI, Subsection IWL, including the 2002 and 2003 Addenda.

In conformance with 10 CFR 50.55a(g)(4)(ii), the PVNGS IWL 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.

The ASME Section XI, Subsection IWL program addresses the requirements for the containment inservice inspection intervals for the concrete and the post-tensioning system for each of the containment structures. Plant surveillance tests verify the structural integrity of the containment tendon system and specify the work necessary for the verification of containment tendon integrity.

NUREG-1801 Consistency

The ASME Section XI, Subsection IWL program is an existing program that is consistent with NUREG-1801, Section XI.S2, ASME Section XI, Subsection IWL.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The ASME Section XI, Subsection IWL program inspects the post-tensioned concrete containment in accordance with 10 CFR 50.55a(b)(2)(viii)(A through E). When observed degradation could indicate the presence of degradation in inaccessible areas, or the conditions described in 10 CFR 50.55a(b)(2)(viii)(C or D) are detected, the ISI Program Engineer shall be notified, and the conditions shall be included in the ISI Summary report. A copy of the ISI Summary Report shall be transmitted to the NRC within 90 days after the completion of the refueling outage. In addition to ISI Summary report requirements, a special report shall be prepared and submitted to the NRC within 30 days after the detection of any abnormal degradation of the containment concrete and/or post-tensioning system, in accordance with Technical Specifications.

A review of PVNGS operating experience has identified only two instances where observed degradation was significant enough to warrant inclusion in a Summary Report. The grease spots identified in these cases are located on the containment exterior concrete surface. An engineering evaluation determined that these are cosmetic conditions, and there are no detrimental affects to the structure.

~~NRC Information Notice IN 99-10, "*Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments*" was issued to notify licensees of the types of degradation observed on the prestressed tendon systems. APS reviewed the information documented in the Information Notice for applicability. The existing PVNGS Tendon Integrity Surveillance procedures are based on the guidance of Regulatory Guide 1.35. The degradation and conditions discussed in the Information Notice are monitored and evaluated per Tendon Integrity surveillance procedures. A trend of degradation described in IN 99-10 has not occurred at PVNGS.~~ For discussion of IN 99-10, see Section B3.3, Concrete Containment Tendon Prestress.

Conclusion

The continued implementation of the ASME Section XI, Subsection IWL 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.

B2.1.32 Structures Monitoring Program

Program Description

The Structures Monitoring Program manages cracking, loss of material, and change in material properties by monitoring the condition of structures and structural supports that are within the scope of license renewal. The program implements the requirements of 10 CFR 50.65 (Maintenance Rule) and is consistent with the guidance of NUMARC 93-01, Rev 2 and Regulatory Guide 1.160, Rev. 2. The Structures Monitoring Program provides inspection guidelines and walkdown checklists for concrete elements, structural steel, masonry walls, structural features (e.g. caulking, sealants, roofs, etc.), structural supports, and miscellaneous components such as doors. The scope of the Structures Monitoring Program includes all masonry walls and water-control structures within the scope of license renewal. The program also monitors settlement for each major structure and inspects supports for equipment, piping, conduit, cable tray, HVAC, and instrument components. The scope of the Structures Monitoring Program does not include the inspection of the supports specifically inspected per the requirements of the ASME Section XI In-Service Inspection Program. Though coatings may have been applied to the external surfaces of structural members, no credit was taken for these coatings in the determination of aging effects for the underlying materials. The Structures Monitoring Program evaluates the condition of the coatings as an indication of the condition of the underlying materials.

Periodic inspections required by the Structures Monitoring Program are performed and documented per plant procedures. Initial baseline inspections under the Structures Monitoring Program were performed from June 1994 to June 1996. Each of the spray ponds is inspected every five years, and settlement monitoring surveillance is performed for each major structure every five years. For other inspections, representative SSCs are monitored at each of the three units, such that the equivalent of one complete unit is inspected every 10 years. All three units will be 100% inspected (with the possible exception of inaccessible areas) within a 30-year period.

NUREG-1801 Consistency

The Structures Monitoring Program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI.S6, "Structures Monitoring Program".

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

The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program.

Acceptance Criteria - Element 6

The Structures Monitoring Program will be enhanced to define the specific criteria for categorizing deficiencies for concrete inspections.

Operating Experience

Miscellaneous openings and gaps in barriers that may impact the environmental equipment qualifications at PVNGS were reviewed and all identified deficiencies were corrected in accordance with NRC Information Notice IN 95-52 "*Barrier and Seals between Harsh Environments*".

NRC Information Notice IN 2002-12 "*Submerged Safety-Related Electrical Cables*" identified several failures and weaknesses associated with protracted submergence in water of electrical cables that feed safety-related equipment. Significant amounts of water have been found in various manholes and the entry is from an unknown source. The intrusion of water into the manholes is being effectively controlled through a pumping program.

NRC Information Notice IN 2003-08 "*Potential Flooding through Unsealed Concrete Floor Cracks*" identified failures involving flooding of rooms containing safety-related panels and equipment as a result of fire water seepage through unsealed concrete floor cracks. No through cracking has been identified at PVNGS and the program has been revised to provide guidance for the identification of through wall cracks in flood barriers in the future.

NRC Information Notice IN 2005-11, "*Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains*" identified the possibility of flooding safety-related equipment as a result of (1) equipment hatch floor plugs that are not water tight and (2) blockage of equipment floor drain systems that are credited to mitigate the effects of flooding. All hatches/plugs that are credited as flood barriers are water tight. Instructions were developed to provide removal and reinstallation instructions for hatches and plugs to maintain the required seals.

Adverse and critical conditions were found on the roof of Unit 1's Turbine Building. These conditions included punctured membrane and rigid insulation, deteriorated tar patches with

mesh reinforcement exposed, damaged flashing exposing the roof membrane seal, raised blisters/raised areas in the membrane, several long areas of damaged flashing, and large cracks through the roof membrane into the rigid insulation. The large cracks and large blister/raised areas in the roof membrane are significant leakage paths and classify the condition of the roof at Elevation 240' as critical. A previously issued CRDR addressed the concern that in inclement weather the Turbine building had experienced consistent and dependable flooding, which had caused equipment failure. To address these concerns Unit 1's Turbine Building roof was replaced. Unit 2 and 3's Turbine Building roofs have been previously replaced.

Conclusion

The continued implementation of the Structures Monitoring 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~~ NB-3222.4 of ~~the~~ Section III of the ASME Boiler and Pressure Vessel Code. An equivalent term ~~I(t)~~ I_t is defined for valves in ~~Paragraph NB-3552~~ Subsubarticle NB-3550. The acceptance criterion for systems and components designed to these requirements is that U or ~~I(t)~~ 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~~2) 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~~2) are those with relatively low design fatigue usage values, and therefore, for which cycle counting will suffice to demonstrate design basis compliance. A fatigue monitoring program that incorporates a three-dimensional, six-element model meeting ASME III NB-3200 requirements will be used for stress-based fatigue monitoring (SBF).

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®~~ fatigue monitoring 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®~~ automatically acquired 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

No later than two years p~~P~~rior 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.

Detection of Aging Effects – Element 4

The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. A fatigue monitoring software program that incorporates a three-dimensional, six-element model meeting ASME III NB-3200 requirements will be used for stress-based fatigue monitoring (SBF).

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-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 vibration 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, 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.