LimerickNPEm Resource

From: Christopher.Wilson2@exeloncorp.com
Sent: Tuesday, June 19, 2012 12:38 PM
To: Kuntz, Robert
Subject: 6.19.12 - LIM - Response to NRC RAI dated 6.12.12 re LGS LRA.pdf
Attachments: 6.19.12 - LIM - Response to NRC RAI dated 6.12.12 re LGS LRA.pdf

Rob…As promised here is the letter we just transmitted to DCC

Hearing Identifier: Limerick_LR_NonPublic
Email Number: 1208

Mail Envelope Properties (9A15F707EB47A04D882D9FEB352EDDF803FE4A27)

Subject: 6.19.12 - LIM - Response to NRC RAI dated 6.12.12 re LGS LRA.pdf
Sent Date: 6/19/2012 12:37:58 PM
Received Date: 6/19/2012 12:38:22 PM
From: Christopher.Wilson2@exeloncorp.com

Created By: Christopher.Wilson2@exeloncorp.com

Recipients:
"Kuntz, Robert" <Robert.Kuntz@nrc.gov>
Tracking Status: None

Post Office: cccmsxch12.energy.power.corp

Files	**Size**	**Date & Time**
MESSAGE	896	6/19/2012 12:38:22 PM
6.19.12 - LIM - Response to NRC RAI dated 6.12.12 re LGS LRA.pdf	969966	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

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10 CFR 50
10 CFR 51
10 CFR 54

June 19, 2012

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Responses to NRC Requests for Additional Information, dated June 12, 2012, related to the Limerick Generating Station License Renewal Application

Reference:
1. Exelon Generation Company, LLC letter from Michael P. Gallagher to NRC Document Control Desk, "Application for Renewed Operating Licenses", dated June 22, 2011
2. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated June 12, 2012 (ML# 12160A012)
3. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated June 12, 2012 (ML# 12157A212)
4. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated June 12, 2012 (ML# 12152A305)

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Limerick Generating Station, Units 1 and 2 (LGS). In the Reference 2, 3 and 4 letters, the NRC requested additional information to support the staffs' review of the LRA.

Enclosed are the responses to these requests for additional information.

This letter and its enclosures contain no new or revised regulatory commitments.

If you have any questions, please contact Mr. Al Fulvio, Manager, Exelon License Renewal, at 610-765-5936.

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

Executed on 06-19-2012

Respectfully,

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Responses to Requests for Additional Information
B: Updates to affected LGS LRA sections

cc: Regional Administrator – NRC Region I
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Project Manager, NRR- DORL Limerick Generating Station
NRC Senior Resident Inspector, Limerick Generating Station
R. R. Janati, Commonwealth of Pennsylvania

Enclosure A

Responses to Requests for Additional Information related to various sections of the LGS License Renewal Application (LRA)

RAI 3.1.1.38-1.2
RAI B.1.4-2
RAI B.2.1.25-1.1
RAI 4.3-10.2

RAI 3.1.1.38-1.2

Background

RAI 3.1.1.38-1.1 requested justification as to why opportunistic inspections and the planned inspection method would be adequate to manage loss of fracture toughness due to thermal aging embrittlement of the ASME Code Class 3 cast austenitic stainless steel (CASS) pump casings in the reactor water cleanup system (RWCU).

Issue:

The response to RAI 3.1.1.38-1.1, provided by letter dated May 31, 2012, does not address the history and results of the previous VT-3 examinations conducted on the CASS pump casings. Therefore, the staff needs the following information to further evaluate the adequacy of the opportunistic inspections for managing aging: (1) when the previous VT-3 examinations were conducted on the CASS pump casings, and (2) the results of the inspections.

Request:

1. If any inspections have been performed on the ASME Code Class 3 CASS pump casings, provide the inspection results including when the inspection(s) were completed.

2. Based on the history and results of the previous inspections using the VT-3 examination, justify why the aging management would not need to ensure the following inspections of the RWCU pump casings: (1) an inspection of the representative pump casing of each unit prior to the period of extended operation and (2) at least, an inspection of the representative pump casing of each unit during the period of extended operation.

Exelon Response:

1. The maintenance procedure for disassembly of the ASME Code Class 3 CASS RWCU pumps includes a step to "examine the casing interior for evidence of defects such as cracks, localized wear or pitting and damaged machined surfaces." The CASS RWCU pumps were last inspected during the conduct of maintenance that required pump disassembly on the dates shown:

RWCU Pump	Date last inspected
1B	12/02/2002
1C	06/12/2001
2B	10/28/2002
2C	01/07/2003

   None of the inspections resulted in the identification of pump casing degradation. Since ASME Section XI does not include requirements to perform internal inspection of ASME Code Class 3 pump casings, examinations utilizing the VT-3 method were not performed.

2. As discussed in the response to request 1, the pump casings have been inspected in accordance with maintenance procedures when opportunities occurred during pump maintenance activities and the results have been acceptable. Since these components are ASME Code Class 3 pumps, VT-3 examinations were not required to be performed. Exelon is proposing to require VT-3 examinations of the casings when the casings are accessible during maintenance activities.

Inspection of a representative pump casing of each unit prior to the period of extended operation or an inspection of the representative pump casing of each unit during the period of extended operation is not needed for the following reasons:

- As discussed in the Exelon response to RAI 3.1.1.38-1.1, the GALL Report does not provide specific guidance for managing thermal aging embrittlement for ASME Code Class 3 pump casings, and ASME Section XI does not include requirements to perform internal inspection of Class 3 pump casings.

  GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)", which manages loss of fracture toughness for safety-related ASME Code Class 1 components, states that "*This program manages loss of fracture toughness in potentially susceptible ASME Code Class 1 piping components made from CASS.*" "*For pump casings and valve bodies, screening for susceptibility to thermal aging is not needed (and thus there are no aging management review line items). For all pump casings and valve bodies, greater than a nominal pipe size (NPS) of 4 inches, the existing ASME Code, Section XI inspection requirements, including the alternate requirements of ASME Code Case N-481 for pump casings, are adequate*." The applicable ASME Code, Section XI inspection requirements for Class 1 pump casings are in Table IWB-2500-1, Examination Category B-L-2, Item No. B12.20, and referenced Note 2. Item No. B12.20 specifies VT-3 examination. Note 2 states that "*examination is required only when a pump or valve is disassembled for maintenance, repair, or volumetric examination*", and clarifies that if the component internals are made accessible more than once per ISI interval, then only one complete examination is required each interval.

  Requiring inspections of nonsafety-related ASME Code Class 3 CASS pump casings prior to or during the period of extended operation is not consistent with guidance in GALL Report AMP XI.M12 and referenced ASME Code Section XI requirements for the aging management of safety-related ASME Code Class 1 pump casings for loss of fracture toughness due to thermal aging embrittlement. Instead, the same examination method (VT-3), and frequency of inspection (opportunistic – when the internal surfaces are made accessible by maintenance) as that required for managing safety-related ASME Code Class 1 CASS pump casings has been proposed.

- These pumps with CASS casings are infrequently in service. The original LGS design included three 50% capacity CASS RWCU pumps on each LGS unit. The "A" RWCU pumps on both LGS units were replaced in the 1999-2001 time-frame with 100% capacity carbon steel pumps that utilize a different design that has proven to be very reliable. Since 2001 the CASS "B" and "C" RWCU pumps have been normally valved out of service, and are operated very infrequently, only when the "A" RWCU pump is not available. Run time data are not collected on these pumps, but the system engineer can only recall the "B" and "C" pumps being used once due to "A" pump unavailability during power operations. This instance was on Unit 1 for about six weeks in 2006. Most of the "B" and "C" pump operating time expected in the future is during refueling outages at operating temperature less than 212 degrees F when maintenance activities take the "A" pump out of service. These pumps are not likely to experience thermal aging embrittlement prior to or during the period of extended operation since thermal aging embrittlement is applicable to components exposed to operating temperatures greater than 482 degrees F, they operated at

these temperatures for only approximately 15 years, and from 2001 through the period of extended operation they are expected to be normally out of service at ambient temperature.

- The work activity to disassemble and reassemble a RWCU pump results in 1 to 3 REM of radiation exposure to personnel. This is a significant amount of radiation exposure and efforts must be made to minimize exposure to plant personnel. Therefore, requiring disassembly/reassembly of these pump casings only to perform internal examination is not consistent with As Low as Reasonably Achievable (ALARA) principles.

For these reasons, performing VT-3 internal surface examination as described above and within the Exelon response to RAI 3.1.1.38-1.1, performed only when the pump casing internal surfaces are made accessible by maintenance or repair, is justified as acceptable to manage thermal aging embrittlement for the CASS RWCU pump casings.

RAI B.1.4-2

Background

Request for additional information (RAI) B.1.4-1, issued on February 16, 2012, requested a description of the programmatic activities that will be used to continually identify aging issues, evaluate them, and as necessary, enhance the aging management programs (AMPs) or develop new AMPs for license renewal. The response dated March 13, 2012, provided additional information regarding the Limerick Generating Station (LGS) Operating Experience program.

On March 16, 2012, the NRC issued LR-ISG-2011-05, “Ongoing Review of Operating Experience” to clarify the staff’s position that license renewal AMPs should be informed, and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience.

Issue

The response to B.1.4-1 described LGS’s plant-specific programmatic framework for considering operating experience. However, in reviewing aspects of the LGS program against the guidance set forth in LR-ISG-2011-05, the staff needs further clarification on the implementation timeframe of the proposed enhancements.

Request

Where the March 13, 2012, response states that enhancements to the Operating Experience program “will be implemented prior to the period of extended operation,” provide further clarification regarding the approximate timeframe this would take place with respect to the period of extended operation. Include any relevant practical consideration that would impact the implementation timeframe.

Exelon Response

As described in our March 13, 2012 response to NRC RAI B.1.4-1, the Operating Experience and Corrective Action programs at LGS have been shown effective in identifying and addressing

aging-related degradation. Also, as previously noted, Exelon has agreed to implement enhancements to provide additional assurance that internal and external operating experience continues to be used effectively to refine, modify or create new aging management programs as appropriate.

Exelon plans to complete these implementation enhancements at LGS within two years following receipt of the renewed operating license, which, assuming the current project milestones are met, would be approximately nine years before LGS Unit 1 enters its PEO. Commitment 46 remains unchanged to require that the changes are in place before the period of extended operation (PEO), to ensure effective aging management programs during the PEO.

The basis for this implementation timing plan is as follows. Exelon believes that it is important, but not urgent, to implement the described enhancements in order to systematically consider and address the aging management aspects of internal and external operating experience. Therefore, a reasonably near-term target has been identified by which time the program enhancements can be accomplished. Although these process changes are being driven by LGS license renewal, Exelon plans to implement the enhancements into its common Operating Experience and Corrective Action processes that are used across the Exelon Nuclear plant fleet. This will require collaboration, coordination and management of these changes within a significant group of people. Activities required to be accomplished will include:

- Developing procedural enhancements that will apply across the fleet, and therefore will need to be reviewed and approved across all the Exelon Nuclear stations as well as the corporate office
- Working within Exelon and with the industry to establish an appropriate threshold for identifying noteworthy age-related issues and appropriate mechanisms to share this information
- Establishing and providing training to those who will be responsible to screen, evaluate and communicate operating experience items related to aging management

The existing LGS Operating Experience and Corrective Action programs have been demonstrated as effective ongoing programs and the development and implementation of the above-listed activities will take some time. Therefore, Exelon believes that planning to complete implementation of the enhancements defined in the response to RAI B.1.4-1 at LGS within two years following receipt of the renewed operating license is an appropriate and responsive schedule.

RAI B.2.1.25-1.1

Background

The response to RAI B.2.1.25-1, provided by letter dated February 15, 2012, states that stress corrosion cracking (SSC) is not applicable for stainless steel surfaces in an outdoor air environment in auxiliary and steam and power conversion systems because:

- Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant.

- A review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components.

- Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition.

Issue:

Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air environment can crack at temperatures as low as 104 to 120 degrees F, depending on humidity, component surface temperature, and contaminant concentration and composition. The staff noted that while the experimental studies demonstrated that cracking can occur in 4 to 52 weeks, the industry operating experience failures did not necessarily occur early in plant life and therefore, the staff cannot conclude that recent inspections are sufficient to demonstrate an aging effect will not occur during the period of extended operation.

Given that a prevailing wind direction does not result in the absence of contaminant deposition by the cooling tower plume, and that information has not been provided on the potential for chloride contamination from the onsite soil or nearby agricultural and industrial sources, the staff lacks sufficient information to conclude that SCC cannot occur in stainless steel components located in an outdoor air environment.

Request:

1. In light of industry operating experience in chloride-containing environments, state the basis for why the chemical compounds in the cooling tower plume cannot result in SCC if plume fallout (regardless of prevailing wind direction) accumulates on the external surfaces of stainless steel piping within the scope of license renewal.

2. State the basis for why chloride contamination is not expected to accumulate on stainless steel components within the scope of license renewal from the soil or nearby agricultural and industrial sources.

Exelon Response:

Requests 1 and 2 are addressed together as follows.

The Issue discussion above references industry operating experience in chloride-containing (coastal) environments. The basis cited in NUREG-1950 for this aging effect refers to a salt-laden atmospheric condition or salt water spray. LGS is in neither a coastal environment nor a salt-laden environment, and is located more than 80 miles from the coast of the Atlantic Ocean. The “Issue” discussion above also refers to industry operating experience in environmental temperatures as low as 104 degrees F. As stated in LRA Appendix E Section 2.9.1, LGS mean monthly temperatures range as high as 73 degrees F, and temperatures rarely exceed 100 degrees F. Actual temperature data was reviewed, and the local environmental temperature exceeded 100 degrees F on only two days over the last ten years, neither of which exceeded 104 degrees F. Additionally, the local environmental temperature exceeded 95 degrees F on only 21 days over the last ten years. LGS operating experience after 25 years of plant operation has not revealed the presence of this aging effect. Therefore, we do not believe that chloride-induced stress corrosion cracking of stainless steel components is an applicable aging effect for LGS.

Regardless, the External Surfaces Monitoring of Mechanical Components aging management program is revised to monitor stainless steel components in an outdoor air environment for SCC. Components directly exposed to the outdoor air environment will be monitored. Components which are jacketed or which are located in underground vaults are shielded from accumulation of potential contaminants in the environment, and are therefore not susceptible to SCC. LRA Tables 3.3.1, 3.3.2-8, 3.3.2-22, 3.4.1, 3.4.2-1, and 3.4.2-2 and LRA sections 3.3.2.1.22, 3.3.2.2.3, 3.4.2.1.1, 3.4.2.2.2, A.2.1.25, and B.2.1.25, are revised as shown in Enclosure B to include this aging effect. A typographical error in section 3.2.2.2.6 is also corrected in this revision.

RAI 4.3-10.2

Background

The response to RAI 4.3-10.1, provided by letter dated May 4, 2012, stated that the steam dryer support brackets were evaluated in the reactor pressure vessel (RPV) stress report and the report stated that "exemption from fatigue analysis per N-415.1 (of the design code) is satisfied." The design code of the brackets was the 1968 Edition of the American Society of Mechanical Engineers (ASME) Code Section III with Addenda through summer 1969. The response also indicated that the control rod guide tube was exempted from fatigue analysis per Paragraph NG-3222.4(d) of the ASME Code Section III.

Issue

The staff noted that the fatigue waiver provisions in N-415.1 of the 1968 Edition of ASME Code Section III with Addenda through summer 1969 discussed that fatigue analyses were not required when all four specific conditions were met. In particular, the staff noted that Condition (a) of N-415.1 required that the specified numbers of times (including startup and shutdown) that the pressure will be cycled from atmospheric pressure to the operating pressure and back to atmospheric pressure shall not exceed certain requirements. The staff noted that the fatigue waiver provision depended on the assumption of the number of occurrence of transients (such as startup and shutdown), which is a time-dependent parameter. The staff noted that the fatigue waiver provisions in Paragraphs NG-3222.4(d) and NB-3222.4(d) of the ASME Code Section III also contained similar transient cycles conditions. The response to RAI 4.3-10.1 did not provide a justification of why the fatigue waivers were not identified as time limited aging analysis (TLAAs) in the License Renewal Application (LRA) in accordance with 10 CFR 54.21(c)(1).

Request

1) Clarify how the fatigue waiver provisions in ASME Code, Section III, compare to the six criteria for TLAAs in 10 CFR 54.3, and justify whether or not the fatigue waivers for the control rod guide tube and the steam dryer support brackets should be identified as TLAAs for the LRA. If the fatigue waivers need to be identified as TLAAs, provide necessary information and LRA revision to support the TLAA disposition.

2) Confirm that all fatigue waiver provisions in the ASME Code, Section III, have been identified as TLAAs, as applicable.

Exelon Response

1) Fatigue exemptions (or fatigue waivers) are TLAAs because they meet all six TLAA criteria defined in 10 CFR 54.3. Criterion 3 is met because the time-limited assumptions are based upon an evaluation of the thermal and pressure transients defined for 40 years in the design specifications for Class 1 components. Therefore, LRA Sections 4.3.1 (including new table 4.3.1-3) and 4.3.4 are revised as shown in Enclosure B to clarify that all fatigue exemptions have been identified as TLAAs and are managed by the Fatigue Monitoring program. UFSAR Supplement Sections A.4.3.1 and A.4.3.4 and Appendix B, Section B.3.1.1 are revised with conforming changes, as shown in Enclosure B. The fatigue exemption for the steam dryer brackets is included in LRA Section 4.3.1, ASME Section III, Class 1 Fatigue Analyses, because the brackets are welded to the inside surface of the RPV and were analyzed within the RPV stress report. The fatigue exemption for the control rod guide tube is included in LRA Section 4.3.4, Reactor Vessel Internals Fatigue, because it was analyzed in a stress report for the RPV internals.

2) The RPV components that meet the exemption criteria of ASME Section III, N-415.1 are listed below:

    a) Capped CRD-HSR nozzle (N-9)
    b) Head spray nozzle (N-6A)
    c) Spare nozzle (N-6B)
    d) Vent nozzle (N-7)
    e) Steam dryer support brackets
    f) Guide rod brackets
    g) Core spray brackets
    h) Steam dryer hold-down brackets
    i) Surveillance specimen brackets
    j) Feedwater sparger brackets
    k) Jet pump riser pads
    l) Top head lifting lugs

The RPV internals component that meets the exemption criteria of ASME Section III, NB-3222.4 (d) is the control rod guide tube.

All fatigue exemptions for ASME Section III, Class 1 components and for RPV internals components have been identified as TLAAs, as described in the revisions to LRA Sections 4.3.1 and 4.3.4 shown in Enclosure B. They are dispositioned per 10 CFR 54.21(c)(1)(iii).

(Note: The TLAA disposition for RPV internals fatigue TLAAs was revised from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii) in the response to RAI 4.3-10, as shown in an Exelon letter dated February 29, 2012.)

Enclosure B
LGS License Renewal Application Updates

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A.
- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and strikethroughs for deleted text.
    - The only exception to this convention is within the response to **RAI 4.3-10.2** because an entirely new table is provided; therefore text is not shown in bold/italicized font.

As a result of the response to **RAI B.2.1.25-1.1** provided in Enclosure A of this letter, LRA Tables 3.3.1, 3.3.2-8, 3.3.2-22, 3.4.1, 3.4.2-1, and 3.4.2-2 are revised as follows:

Page 3.3-34

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-4	Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	~~Not applicable.~~ ***Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.25) program will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air-outdoor in the Emergency Diesel Generator and Safety Related Service Water systems.*** See Subsection 3.3.2.2.3.

Table 3.3.2-8, page 3.3-132:

Table 3.3.2-8 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.H2.AP-221	3.3.1-6	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.25)***	VII.H2.AP-209	3.3.1-4	~~I, 6~~ ***A***
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-273	3.3.1-95	A
			Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H2.AP-128	3.3.1-83	A

Table 3.3.2-8, page 3.3-141:

~~6. Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.~~

Table 3.3.2-22, page 3.3-230:

Table 3.3.2-22 Safety Related Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Spray Nozzles	Spray	Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.C3.AP-221	3.3.1-6	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.25)***	VII.C3.AP-209	3.3.1-4	~~I, 3~~ ***A***
			Air/Gas - Wetted (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.D.AP-81	3.3.1-56	E, 2
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.A-54	3.3.1-40	A

Table 3.3.2-22, page 3.3-231 (This information is provided for clarity; there is no change to this portion of the table):

Table 3.3.2-22 Safety Related Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.C3.AP-221	3.3.1-6	E, 1
				None	None	VII.C3.AP-209	3.3.1-4	I, 3

<u>Table 3.3.2-22, page 3.3-232:</u>

3. ***These components are enclosed in underground vaults and are shielded from accumulation of potential contaminants. Therefore,*** ~~Based on LGS environmental conditions and verified by operating experience review,~~ cracking is not an applicable aging effect ~~for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking~~.

<u>Table 3.4.1, page 3.4-12:</u>

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-2	Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated (See subsection 3.4.2.2.2)	~~Not applicable.~~ ***Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.25) program will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air-outdoor in the Circulating Water system.*** See Subsection 3.4.2.2.2.

<u>Table 3.4.2-1, page 3.4-30:</u>

Table 3.4.2-1 Circulating Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.E.SP-127	3.4.1-3	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.25)***	VIII.E.SP-118	3.4.1-2	~~I, 4~~ ***A***
			Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.F.SP-117	3.4.1-21	C

<u>Table 3.4.2-1, page 3.4-32:</u>

Plant Specific Notes:

~~4. Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.~~

Table 3.4.2-2, page 3.4-35 (This information is provided for clarity; there is no change to this portion of the table):

Table 3.4.2-2 Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.E.SP-127	3.4.1-3	A
				None	None	VIII.E.SP-118	3.4.1-2	I, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	VIII.E.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-16	A

Table 3.4.2-2, page 3.4-36:

Plant Specific Notes:

1. ***These components are jacketed and not directly exposed to the outdoor air environment. Therefore,*** ~~Based on LGS environmental conditions and verified by operating experience review,~~ cracking is not an applicable aging effect ~~for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking~~.

As a result of the response to **RAI B.2.1.25-1.1** provided in Enclosure A of this letter, LRA Sections 3.2.2.2.6, 3.3.2.1.22, 3.3.2.2.3, 3.4.2.1.1, 3.4.2.2.2, A.2.1.25, and B.2.1.25 are revised as follows:

3.2.2.2.6 Cracking due to Stress Corrosion Cracking

Item Number 3.2.1-7 is not applicable to LGS. For the ESF Systems, there are no stainless steel components exposed to an outdoor air environment. Therefore, ~~S~~SC***C*** is not applicable for ESF Systems at LGS.

3.3.2.1.22 Safety Related Service Water System

Aging Effects Requiring Management

The following aging effects associated with the Safety Related Service Water System components require management:

- ***Cracking***
- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

3.3.2.2.3 Cracking due to Stress Corrosion Cracking

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, and piping elements exposed to outdoor air, including air which has recently been introduced into buildings, such as near intake vents. ~~Item Number 3.3.1-4 is not applicable to LGS.~~ ***The outside air at LGS is not conducive to stress corrosion cracking.*** The Limerick site is located more than 80 miles from the coast of the Atlantic Ocean. The major transportation routes near the site are at least one mile from this site. Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant. ***Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air environment can crack at temperatures as low as 104 to 120 degrees F, depending on humidity, component surface temperature, and contaminant***

concentration and composition. Outdoor air temperatures at LGS rarely exceed 100 degrees F. In the last ten years, temperature exceeded 100 degrees F on two days, and exceeded 95 degrees F on twenty-one days, which further reduces susceptibility to SCC. A review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components. Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. ***Nevertheless, consistent with NUREG-1801, cracking of stainless steel components directly exposed to outdoor air is identified as an aging effect requiring management, and is managed by the External Surfaces Monitoring of Mechanical Components aging management program. There are no stainless steel components in Auxiliary Systems that are located near air intake vents.*** ~~Therefore, the outside air at LGS is not conducive to stress corrosion cracking, and SSC is not applicable for stainless steel surfaces in an outdoor air environment in Auxiliary Systems at LGS.~~

3.4.2.1.1 Circulating Water System

Aging Effects Requiring Management

The following aging effects associated with the Circulating Water System components require management:

- ***Cracking***
- Hardening and Loss of Strength
- Loss of Material
- Loss of Preload

3.4.2.2.2 Cracking due to Stress Corrosion Cracking (SCC)

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, and piping elements exposed to outdoor air, including air which has recently been introduced into buildings, such as near intake vents. ~~Item Number 3.4.1-2 is not applicable to LGS.~~ ***The outside air at LGS is not conducive to stress corrosion cracking.*** The Limerick site is located more than 80 miles from the coast of the Atlantic Ocean. The major transportation routes near the site are at least one mile from this site. Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant. ***Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air***

environment can crack at temperatures as low as 104 to 120 degrees F, depending on humidity, component surface temperature, and contaminant concentration and composition. Outdoor air temperatures at LGS rarely exceed 100 degrees F. In the last ten years, temperature exceeded 100 degrees F on two days, and exceeded 95 degrees F on twenty-one days, which further reduces susceptibility to SCC. A review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components. Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. ***Nevertheless, consistent with NUREG-1801, cracking of stainless steel components directly exposed to outdoor air is identified as an aging effect requiring management, and is managed by the External Surfaces Monitoring of Mechanical Components aging management program. There are no stainless steel components in Steam and Power Conversion Systems that are located near air intake vents.*** ~~Therefore, the outside air at LGS is not conducive to stress corrosion cracking, and SCC is not applicable for stainless steel surfaces in an outdoor air environment in Steam and Power Conversion systems at LGS.~~

A.2.1.25 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric materials through visual inspection of external surfaces for evidence of loss of material ***and cracking***. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers.

B.2.1.25 External Surfaces Monitoring of Mechanical Components

Program Description:

The External Surfaces Monitoring aging management program is a new program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, and other components within the scope of license renewal. The program manages aging effects through visual inspection of external surfaces for evidence of loss of material ***and cracking*** in air-indoor, air-outdoor, and air/gas wetted environments. Visual inspections are augmented by physical manipulation as necessary for evidence of hardening and loss of strength.

Materials of construction inspected under this program include aluminum, carbon steel, copper alloy, ductile cast iron, elastomers, gray cast iron, and stainless steel. Examples of components this program inspects are piping and piping components, ducting, heat exchangers, tanks, pumps, expansion joints, and hoses. The inspection parameters for metallic components include material condition, which consists of evidence of rust,

corrosion, overheating, blistering, ***cracking,*** and discoloration; evidence of insulation damage or wetting; degradation, blistering, and peeling of protective coatings; unusual leakage from piping, ducting, or component bolted joints. Coating degradation is used as an indicator of possible underlying degradation of the component. Inspection parameters for elastomeric components include hardening, discoloration, cracking, dimensional changes, and thermal exposure.

Conclusion

The new External Surfaces Monitoring of Mechanical Components program will provide reasonable assurance that the loss of material***, cracking,*** and hardening and loss of strength aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

As a result of the response to RAI 4.3-10.2 provided in Enclosure A of this letter, LRA Section 4.3.1, TLAA Evaluation is revised as shown below:

4.3.1 ASME SECTION III, CLASS 1 FATIGUE ANALYSES

TLAA Description:

The LGS reactor pressure vessel (RPV) and reactor coolant pressure boundary (RCPB) piping and components were designed in accordance with the ASME Code Section III, Class 1 design requirements. Fatigue analyses ***and fatigue exemptions*** were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. These Class 1 fatigue analyses ***and fatigue exemptions*** evaluated an explicit number and type of transients that were postulated in the design specifications to envelope the number of occurrences possible during the 40-year design life of the plant. The Class 1 vessel and piping analyses were required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the design limit 1.0 when the component is exposed to all of the postulated transients. The Class 1 valve analyses were required to demonstrate that the valves can be operated for a minimum of 2,000 cycles and that the fatigue usage factor for step changes in fluid temperature I_t does not exceed a limit of 1.0.

Since the calculation of fatigue usage factors is part of the current licensing basis and is used to support safety determinations and since the number of occurrences of each transient type was based upon 40-year assumptions, these Class 1 fatigue analyses ***and fatigue exemptions*** have been identified as Time-Limited Aging Analyses (TLAAs) requiring evaluation for the period of extended operation.

TLAA Evaluation:

The ASME Section III, Class 1 fatigue analyses for LGS include the stress reports for the Reactor Pressure Vessel (RPV), reactor coolant pressure boundary (RCPB) piping and components, including Class 1 valves. ***These stress reports include fatigue analyses and fatigue exemptions, where applicable, that have been identified as TLAAs since they are based upon 40-year design transients. The fatigue exemptions are listed in LRA Table 4.3.1-3.*** The current Class 1 fatigue analyses are based upon the same 40-year design transients as the original analyses, which are those listed in UFSAR Table 3.9-2, "Plant Events," for the RPV and UFSAR Table 5.2-9 "RCPB Operating Thermal Cycles" for the RCPB components (Reference 4.7.18). The RPV was also evaluated for MSRV discharge loads and LOCA-induced pool dynamic loads, including condensation oscillation and chugging cycles. Each Class 1 fatigue analysis demonstrates that the component has a CUF value that does not exceed the design Code limit of 1.0. ***Each fatigue exemption demonstrates that the applied cyclic loadings meet the exemption criteria of the design code and therefore a fatigue usage factor computation is not required.***

Each of the Class 1 fatigue analyses ***and fatigue exemptions*** may be evaluated for 60 years by determining whether or not the numbers of cycles assumed in the analysis will remain bounding of the actual numbers of cycles predicted to be experienced by the component through the end of the period of extended operation. The 60-year transient projections described below demonstrate that the numbers of cycles currently analyzed for LGS Class 1 components, which are considered to be design transient limits, will not be exceeded during the period of extended operation. Therefore, the current Class 1 fatigue analyses ***and fatigue exemptions have been*** ~~will be~~ demonstrated to remain valid for the period of extended operation.

Using transient cycle monitoring data from the Fatigue Monitoring (B.3.1.1) program, 60-year transient projections were developed, as shown in Table 4.3.1-1 for Unit 1 and Table 4.3.1-2 for Unit 2. The third column lists the cumulative number of cycles to-date, including cycles that occurred during pre-operational startup testing and during all plant operations through early January 2011. The fourth column shows the numbers of cycles projected to occur over 60 years, based upon a linear extrapolation using the average rate of occurrence during the baseline period that started at the beginning of operating cycle 1 and ended in January 2011 for each unit. The fifth column shows additional cycles applied to add margin for transients with low rates of past occurrence. The sixth column shows the adjusted 60-year projections, which sums the cycles-to-date, the 60-year projected cycles, and the added margin. The seventh column is the current design cycle limit, which is the number of cycles analyzed in the Class 1 fatigue analyses.

The projections show that the current design cycle limits will not be exceeded during 60 years of plant operation for Unit 1 and Unit 2. Therefore, none of the transient types are expected to be exceeded during the period of extended operation. Therefore, the Class 1 fatigue analyses ***and fatigue exemptions*** will remain valid for the period of extended operation. This is based upon the assumption that the rates of cycle occurrence in the future will not exceed the average rates of occurrence of past cycles. Each of these transient projections were trended graphically to determine if recent rates of occurrence could be higher than the overall average rate of occurrence. The trending shows that recent transient occurrence rates are bounded by the average occurrence rates. In order to assure that this conclusion and basis remains valid, the Fatigue Monitoring (B.3.1.1) program will be used to monitor and track transient cycle occurrences through the end of the period of extended operation to ensure that these limits are not exceeded.

The program includes requirements that trigger corrective action if a transient approaches a cycle limit. If the rates of future occurrence increase for any reason corrective action may include ***revision*** ~~reanalysis~~ of affected Class 1 ***fatigue analyses and fatigue exemptions*** ~~components~~ to address increased numbers of cycles, repair, or replacement of the component. Since the Fatigue Monitoring program will be needed to validate the transient projection assumptions, it ***is*** ~~will be~~ credited for managing these Class 1 fatigue TLAAs for the period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be managed by the Fatigue Monitoring (B.3.1.1) program for the period of extended operation.

As a result of the response to RAI 4.3-10.2 provided in Enclosure A of this letter, LRA Section 4.3.1 is revised to add LRA Table 4.3.1-3, as shown below (without bold italics since it is a new table):

Table 4.3.1-3 Components With Fatigue Exemptions
RPV Components Exempt Per ASME Section III, N-415.1
a) Capped CRD-HSR nozzle (N-9)
b) Head spray nozzle (N-6A)
c) Spare nozzle (N-6B)
d) Vent nozzle (N-7)
e) Steam dryer support brackets
f) Guide rod brackets
g) Core spray brackets
h) Steam dryer hold-down brackets
i) Surveillance specimen brackets
j) Feedwater sparger brackets
k) Jet pump riser pads
l) Top head lifting lugs
RPV Internals Components Exempt Per ASME Section III, NB-3222.4 (d)
a) Control rod guide tube

As a result of the response to RAI 4.3-10.2 provided in Enclosure A of this letter, LRA Section 4.3.4 is revised as shown below:

4.3.4 REACTOR VESSEL INTERNALS FATIGUE ANALYSES

TLAA Description:

LGS reactor internals were designed and procured prior to the issuance of ASME Section III, Subsection NG. However, an earlier draft of the ASME Code was used as a guide in the design of the reactor internals. Subsequent to the issuance of Subsection NG, comparisons were made that ensure the pre-NG design meets the equivalent level of safety as presented by Subsection NG. These fatigue analyses have been identified as TLAAs that require evaluation for the period of extended operation.

TLAA Evaluation:

The RPV and RPV internal components were included in the NSSS New Loads Design Adequacy Evaluations performed for each unit to address the effects of plant-specific seismic loadings and suppression pool hydrodynamic structural loadings on NSSS equipment. These evaluations included fatigue analyses of components if the applied loadings exceed certain thresholds. The fatigue analyses ***and fatigue exemptions*** performed for the reactor internals components are ***TLAAs that are*** based upon the same set of design transients as those used in the fatigue analyses for the reactor pressure vessel. This includes MSRV discharge loads and LOCA-induced loads, including condensation oscillation and chugging cycles. As shown on Tables 4.3.1-1 and 4.3.1-2, transient cycle projections were prepared that demonstrate these design transient cycle limits will not be exceeded in 60 years. In order to ensure that these ***fatigue analyses and fatigue exemptions*** ~~cycle projections will~~ remain valid, the Fatigue Monitoring program will be used to manage fatigue of these components through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The reactor vessel internals fatigue analyses will be managed by the Fatigue Monitoring program through the period of extended operation.

As a result of the response to RAI 4.3-10.2 provided in Enclosure A of this letter, UFSAR Supplement, Sections A.4.3, A.4.3.1, and A.4.3.4 are revised as shown below:

A.4.3 Metal Fatigue

Metal fatigue was considered explicitly in the design process for pressure boundary components designed in accordance with ASME Section III, Class A or Class 1 requirements. Metal fatigue was evaluated implicitly for components designed in accordance with ASME Section III, Class 2 or 3 requirements or ANSI B31.1 requirements. ~~Each of~~ ***T***hese fatigue analyses and ***fatigue exemptions*** ~~evaluations~~ are considered to be Time-Limited Aging Analyses (TLAAs) requiring evaluation for the period of extended operation in accordance with 10 CFR 54.21(c).

A.4.3.1 ASME Section III, Class 1 Fatigue Analyses

The LGS reactor pressure vessel (RPV) and reactor coolant pressure boundary (RCPB) piping and components were designed in accordance with the ASME Code Section III, Class 1 requirements. Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. These Class 1 fatigue analyses ***are included in stress reports that*** evaluated an explicit number and type of transients to envelope the number of occurrences projected during the 40-year design life of the plant. ***These stress reports include fatigue analyses and fatigue exemptions, where applicable, that have been identified as TLAAs since they are based upon 40-year design transients.*** Each analysis was required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the design limit of 1.0 when the component is exposed to all of the postulated transients. The Class 1 valve analyses were required to demonstrate that the valves can be operated for a minimum of 2,000 cycles and that the fatigue usage factor for step changes in fluid temperature It does not exceed a limit of 1.0.

The calculation of fatigue usage factors is part of the current licensing basis and is used to support safety determinations and since the number of occurrences of each transient type was based upon 40-year assumptions, these Class 1 fatigue analyses ***and fatigue exemptions*** have been identified as time-limited aging analyses.

Each of the Class 1 fatigue analyses ***and fatigue exemptions*** was evaluated for 60 years by determining that the numbers of cycles assumed in the 40-year analysis will remain bounding of the numbers of cycles projected for the component through the end of the period of extended operation. These 60-year projections were based upon cumulative cycles to-date plus future cycles predicted based upon the average rates of past occurrences. In order to ensure that these ***fatigue analyses and fatigue exemptions*** ~~projections~~ remain valid, the Fatigue Monitoring program will be used to ensure the cycle limits are not exceeded during the period of extended operation. The program includes requirements that trigger corrective action if a transient approaches a cycle limit. Corrective action may include reanalysis of affected Class 1 components to address increased numbers of cycles, repair, or replacement of the component.

The effects of aging on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be adequately managed for the period of extended operation by the Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.4 Reactor Vessel Internals Fatigue Analyses

The RPV and RPV internal components were included in the NSSS New Loads Design Adequacy Evaluations performed for each unit to address the effects of plant-specific seismic loadings and suppression pool hydrodynamic structural loadings on NSSS equipment. These evaluations included fatigue analyses of components if the applied loadings exceed certain thresholds. These fatigue analyses ***and fatigue exemptions*** have been identified as TLAAs that require evaluation for the period of extended operation.

The fatigue analyses ***and fatigue exemptions*** performed for the reactor internals components are based upon the same set of design transients as those used in the fatigue analyses for the reactor pressure vessel. Transient cycle projections were prepared that demonstrate the design transient cycle limits will not be exceeded in 60 years. In order to ensure that these ***fatigue analyses and fatigue exemptions*** ~~cycle projections will~~ remain valid, the Fatigue Monitoring program will be used to manage fatigue of these components through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

As a result of the response to RAI 4.3-10.2 provided in Enclosure A of this letter, LRA Appendix B, Section B.3.1.1, Fatigue Monitoring, Program Description, is revised as shown below:

B.3.1.1 Fatigue Monitoring

Program Description

The Fatigue Monitoring program is an existing program that monitors and tracks the number of critical thermal, pressure, and seismic transients specified in Technical Specification 5.6 as well as those listed in LGS UFSAR Table 3.9-2, "Design Events," and Table 5.2-9, “RCPB Operating Thermal Cycles.” The program requires comparison of the actual event parameters (pressure, temperature, or flow rate changes) to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. The program includes counting the operational transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting fatigue analysis, including environmental fatigue analyses, which is the cycle limit for each transient type. For license renewal, fatigue cycle monitoring data was trended to predict the numbers of operational transient cycles that will occur during 60 years. These projections show that the current cycle limits will not be exceeded in 60 years. Therefore, the current cycle limits will be maintained for the period of extended operation.

The effect of the reactor coolant environment on reactor coolant pressure boundary (RCPB) component fatigue life has been determined by performing environmental fatigue analyses for a sample of critical locations selected using NUREG/CR-6260 guidance. Additional environmental fatigue analyses were performed for limiting locations within each RCPB system and each RPV component with a Class 1 fatigue analysis. The RCPB systems at LGS are designed in accordance with ASME Section III, Class 1 design requirements. Environmentally-adjusted fatigue usage factors (CUF_{en}) were computed in accordance with the requirements specified in NUREG/CR-6909 for all materials.

An environmental fatigue correction factor was determined for each material within the analyzed component that contacts reactor coolant to assure the limiting case was analyzed. The fatigue design curves provided in NUREG/CR-6909 were used to determine the allowable numbers of cycles for all stainless steel and nickel alloy materials. The resulting CUF_{en} values do not exceed the design Code limit of 1.0. The feedwater nozzles have been qualified for 51 years. Corrective action will be required prior to reaching the limit of 1.0 for these nozzles. Maintaining the cumulative cycle counts below the cycle limits assures that the CUF value does not exceed the Code design limit of 1.0, including environmental effects where applicable.

If a cycle limit is approached, corrective actions are triggered to prevent exceeding the limit. The fatigue analyses ***and applicable fatigue exemptions*** may be revised to account for increased numbers of cycles or increased transient severity such that the CUF value does not exceed the Code design limit of 1.0, including environmental effects where applicable. Environmental fatigue analyses will be reviewed and updated if necessary to assure the liming locations within each Class 1 system and RPV component are evaluated for reactor water environmental effects.