Progress Energy
Crystal River Nuclear Plant
Docket No. 50-302
Operating License No. DPR-72

Ref: 10 CFR 54

December 30, 2009
3F1209-12

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

Subject: Crystal River Unit 3 – Response to Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant, License Renewal Application (TAC NO. ME0274) and Amendment #8

References: (1) CR-3 to NRC letter, 3F1208-01, dated December 16, 2008, "Crystal River Unit 3 – Application for Renewal of Operating License"

(2) NRC to CR-3 letter, dated December 1, 2009, "Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant, License Renewal Application (TAC NO. ME0274)"

Dear Sir:

On December 16, 2008, Florida Power Corporation (FPC), doing business as Progress Energy Florida, Inc. (PEF), requested renewal of the operating license for Crystal River Unit 3 (CR-3) to extend the term of its operating license an additional 20 years beyond the current expiration date (Reference 1). Subsequently, the Nuclear Regulatory Commission (NRC), by letter dated December 1, 2009, provided a request for additional information (RAI) concerning the CR-3 License Renewal Application (Reference 2). Enclosure 1 to this letter provides the response to Reference 2 and supplemental information supporting previous responses to RAI 2.3-04, RAI 2.4-1, and RAI B.2.30-4. In addition, Enclosure 2 provides an amendment to the License Renewal Application.

No new regulatory commitments are contained in this submittal.

If you have any questions regarding this submittal, please contact Mr. Mike Heath, Supervisor, License Renewal, at (910) 457-3487, e-mail at mike.heath@pgnmail.com.

Sincerely,

Jon A. Franke
Vice President
Crystal River Unit 3

JAF/dwh

Enclosures: 1. Response to Request for Additional Information
2. Amendment #8, Changes to the License Renewal Application

xc: NRC CR-3 Project Manager
NRC License Renewal Project Manager
NRC Regional Administrator, Region II
Senior Resident Inspector

A001
NRR

**STATE OF FLORIDA**

**COUNTY OF CITRUS**

Jon A. Franke states that he is the Vice President, Crystal River Nuclear Plant for Florida Power Corporation, doing business as Progress Energy Florida, Inc.; that he is authorized on the part of said company to sign and file with the Nuclear Regulatory Commission the information attached hereto; and that all such statements made and matters set forth therein are true and correct to the best of his knowledge, information, and belief.

Jon A. Franke
Vice President
Crystal River Nuclear Plant

The foregoing document was acknowledged before me this 30 day of December, 2009, by Jon A. Franke.

Signature of Notary Public
State of Florida

CAROLYN E. PORTMANN
Notary Public - State of Florida
My Commission Expires Mar 1, 2010
Commission # DD 524380
Bonded By National Notary Assn.

(Print, type, or stamp Commissioned Name of Notary Public)

Personally Known ✓ -OR- Produced Identification ______

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ENCLOSURE 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

# RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

## RAI 3.1.2.1-4

Background

In LRA Table 3.1.2-1, the applicant addresses the steam generator tube sheets aging effects for reactor coolant and air-indoor uncontrolled. However, the applicant does not address the aging effect for the surface of the low alloy steel steam generator tube sheets in the environment of secondary feedwater/steam.

Issue

For similar component/environment combinations (such as GALL Report item IV.D2-8) the GALL Report identifies an aging effect of concern of loss of materiel due to general, pitting, and crevice corrosion.

Request

Clarify why this aging effect for the steam generator tube sheets is not of concern at CR-3. If you need to address this aging effect, please clarify how it will be managed.

***Response***

*An evaluation of the tubesheets exposed to treated water has been performed and resulted in the following aging effects requiring management:*

- *Cumulative Fatigue Damage due to Fatigue (which is a Time-Limited Aging Analysis - TLAA)*
- *Loss of material due to general, crevice, and pitting corrosion that will be managed by a combination of the Water Chemistry and One-Time Inspection Programs*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

## RAI 3.1.2.1-5

Background

LRA table 3.1.1 item 59, states that the aging effect of wall thinning due to flow accelerated corrosion for steam generator feedwater and auxiliary feedwater nozzles and safe ends, and steam nozzles and safe ends is not applicable to its steam generators. This aging effect corresponds to GALL Report item IV.D2-7.

Issue

The staff noted that the LRA does not provide any explanation for eliminating this aging effect.

Request

Clarify why wall thinning due to flow accelerated corrosion for steam generator feedwater and auxiliary feedwater nozzles and safe ends, and steam nozzles and safe ends is not an aging effect of concern at CR-3.

***Response***

*As described in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, Page IX-30:*

> *Susceptibility may be determined using the review process outlined in Section 4.2 of NSAC-202L-R2 recommendations for an effective FAC program.*

*The associated components identified in NUREG-1801 are as follows:*

- *Feedwater Nozzles and Safe Ends,*
- *Auxiliary Feedwater Nozzles and Safe Ends; and*
- *Steam Nozzles and Safe ends.*

*The configuration of the main feedwater (MFW) piping and connections for the Once-Through Steam Generator (OTSG) at Crystal River Unit 3 (CR-3) is as follows: The MFW header is comprised of two separate half-torus segments that extend around the shell. Thirty-two riser pipe assemblies extend upward from the headers, turn 90 degrees, and connect to a MFW spray nozzle through a flanged connection at the shell opening. The configuration is not a standard nozzle and safe end as described in NUREG-1801. The OTSG header is included within the scope of the Flow Accelerated Corrosion (FAC) Program up to the MFW Spray Nozzle Flanges. The plant-specific susceptibility evaluation was performed for the flanges and it was determined that they were not susceptible.*

*The configuration of the auxiliary feedwater (AFW) piping and connections for the OTSG is as follows: The AFW is supplied to the inlet pipes through a 6 inch Schedule 80 external header. The AFW header is a two-piece doughnut shaped ring joined by flanges to form a single header. The OTSG utilizes a flanged connection that is made with a gasket and low-alloy steel studs and nuts. A riser pipe, similar to those of the MFW System, leads from the header to each AFW inlet pipe. The configuration is not a standard nozzle and safe end as described in NUREG-1801. For lines that are not normally operated, Section 4.2 of NSAC-202L, Revision 2, states:*

> *Systems or portions of systems with no flow, or those that operate less than 2% of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F (93°C) less than 2% of the plant operating time. Caution—if the actual operating conditions of the system cannot be confirmed (e.g., leaking valve, time of system operation cannot be confirmed), or if the service is especially severe (e.g., flashing flow), that system should not be excluded from evaluation based on operating time alone. A further caution—some lines that operate less than 2% of the time have experienced damage caused by FAC. These lines include Feedwater Recirculation, startup condensate lines, High Pressure Coolant Injection (HPCI), by-pass lines to the condenser, and Reactor Coolant Inventory Control (RCIC). Such lines should be excluded only if no wear has been observed and*

*continued operation under existing parameters is assured. Balancing lines between normally flowing lines should not be excluded based on this criterion.*

*The plant-specific susceptibility evaluation was performed for these AFW components, and it was determined that they were not susceptible.*

*NSAC-202L, Revision 2, excludes, "Superheated steam systems or portions of systems with no moisture content, regardless of temperature or pressure levels." The OTSG Steam Outlet Nozzles are exposed to superheated steam and are excluded on that basis.*

*The susceptibility of the Replacement OTSGs (ROTSG) to FAC is addressed in the response to RAI B.2.9-6.*

**RAI 3.1.2.1-6**

Background

LRA Table 3.1.2-1 addresses AMR item of reduction of heat transfer effectiveness due to fouling of heat transfer surfaces for nickel-alloy steam generator tubes and sleeves exposed to reactor coolant (inside) and to treated water (outside). As stated by the applicant, this aging effect is not in the GALL Report (note H).

Issue

The applicant states in plant-specific note 104 that fouling of the steam generator tubes has not been observed at CR-3. It is not clear to the staff whether this comment applies to fouling from the inner diameter (ID), outer diameter (OD), or both.

Moreover, the applicant does not explain how the AMPs it prescribes, especially the steam generator tube integrity program, can manage ID fouling of the steam generator tubes.

Request

1. Explain why you selected the aging mechanism of fouling of the steam generator tubes from the inside surface.

2. Discuss how the AMPs you prescribed can manage this effect.

***Response***

1. *Although there is no plant-specific operating experience (OE) related to reduction of heat transfer effectiveness due to fouling of heat transfer surfaces on both the primary and secondary sides of the steam generator tubes, the CR-3 aging management review (AMR) methodology assumes the aging effect is applicable in the absence of water chemistry control.*

2. *The aging management strategy will be updated to delete the reliance on the Steam Generator Tube Integrity Program as follows:*

*Reduction of heat transfer effectiveness due to fouling of heat transfer surfaces of the primary and secondary sides of the tubes will be managed by the Water Chemistry Program only.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

*The CR-3 Water Chemistry Program is described in Subsection B.2.2 of the LRA and is consistent with the aging management program (AMP) described in NUREG-1801, Revision 1. The CR-3 Water Chemistry Program is used to control water chemistry for impurities (e.g., dissolved oxygen, chlorides, fluorides, and sulfates) that accelerate corrosion and cracking. This Program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the system-specific limits. NUREG-1801, Revision 1 directs the use of the Water Chemistry Program for managing corrosion on the primary side (reactor coolant) similarly for stainless steel and nickel base alloys (e.g., Volume 2 Items IV.A2-14 and IV.C2-15). NUREG-1801, Revision 1, directs the use of the Water Chemistry Program for managing reduction of heat transfer due to fouling of stainless steel heat exchanger tubes. Therefore, the use of the Water Chemistry Program to manage nickel base alloy heat exchanger tubes for this aging effect is considered acceptable.*

**RAI 3.1.2.1-7**

Background

LRA Table 3.1.2-1 addresses AMR items for loss of material due to crevice and pitting corrosion for the steam generator tubes and sleeves made of nickel base alloys and exposed to reactor coolant (inside).

While the GALL Report does not have an exact corresponding AMR for these steam generator components, the LRA relates the components to GALL Report Item IV.C2-15 which identifies an aging effect of loss of material due to crevice and pitting corrosion in relation to the material and the environment. The LRA states it will manage this aging effect with only the water chemistry program as recommended by GALL Report Item IV.C2-15.

Issue

The staff finds the LRA does not provide enough information to verify whether the water chemistry program according to the GALL item IV.C2-15 is sufficient to manage the aging effect of loss of material due to pitting and crevice corrosion for the steam generator tubes, sleeves and plugs.

The staff concludes that the applicant should apply some condition monitoring water chemistry program or complete this program with a confirmatory inservice inspection-based program, for example on the basis of the steam generator tube integrity program, in order to verify that the water chemistry program achieves its preventive purposes.

Request

Clarify why you consider that the water chemistry program by itself will be sufficient to manage the loss of material due to pitting and crevice corrosion for these components, without any additional condition monitoring or inservice inspection-based program.

***Response***

*NUREG-1801 considers the use of a water chemistry program consistent with the program described in NUREG-1801, XI.M2 as sufficient to manage loss of material due to pitting and crevice corrosion of nickel-based alloys as indicated by Volume 2 Items IV.A2-14, IV.B4-38, and VIII.B1-1, in addition to IV.C2-15. These Volume 2 Items address components as disparate as Reactor Vessel flanges; nozzles; penetrations; pressure housings; safe ends; vessel shells, heads and welds, Reactor Vessel internals components, and Main Steam piping, piping components, and piping elements. The AMR determined that these steam generator subcomponents are consistent with the items represented in NUREG-1801 for component, material, environment, and aging effect; hence the use of Note A.*

**RAI 3.1.2.2.16.2-1**

Background

Section 3.1.2.2.16 of the SRP-LR indicates that stress corrosion cracking can occur for stainless steel pressurizer spray heads. The GALL Report recommends the Water Chemistry and the One-Time Inspection Programs to manage this degradation mechanism.

Issue

LRA Section 3.1.2.2.16.2 indicates that the pressurizer spray heads are not applicable to CR-3 because they have no intended function. It is not clear to the staff why this material must not be controlled under an aging management program.

Request

Provide additional information on why the pressurizer spray heads do not need to be considered for any aging degradation mechanisms and as such, subject to an aging management review.

***Response***

*CR-3 reviewed its design basis information, OE, and report BAW-2244A, "Demonstration of the Management of Aging Effects for the Pressurizer," prepared by the B&W Owners Group (B&WOG) as part of the Generic License Renewal Program, to determine whether or not the pressurizer spray head and internal spray line items were within the scope of License Renewal. On pages 7 and 8 of the Safety Evaluation Report issued for BAW-2244, it is stated:*

> *In their response to RAI NO.7, dated February 20, 1996, the B&WOG stated that the spray head and associated internal spray line items did not support the pressurizer pressure boundary. Therefore, the B&WOG contends that these components were not necessary to shut down the reactor and maintain it in safe shutdown condition; not required to mitigate*

> *design basis accidents as defined by Chapter 15 of each plant's final safety analysis report; and not credited for compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63). Furthermore, the B&WOG stated that industry experience did not support a scenario in which failure of the spray head or internal spray line items leads to a loss of the pressurizer pressure boundary. Consequently, the B&WOG contended that such a scenario was beyond the scope of the pressurizer design and otherwise hypothetical. The staff agreed that the spray head and internal spray line items did not support any of the intended functions defined in 10 CFR 54.4(a) and, therefore, were not within the scope of license renewal.*

*On this basis, CR-3 concluded that the spray head and internal spray line items are not within the scope of License Renewal and, therefore, not subject to AMR.*

**RAI 3.1.2.2.2.1-1**

Background

LRA Section 3.1.2.2.2.1 addresses the loss of material due to general, pitting, and crevice corrosion in the steel PWR once-through steam generator shell exposed to treated water and steam. The staff reviewed LRA Section 3.1.2.2.2.1 against the criteria of SRP-LR Section 3.1.2.2.2.1, which states that loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The LRA considers the same aging mechanisms. It also states that CR-3 will manage the loss of material due to general, pitting and crevice corrosion in the steel components exposed to secondary feedwater/steam and reactor coolant in the steam generator with the Water Chemistry Program. In addition, CR-3 will implement a one-time inspection program for susceptible locations to verify the effectiveness of the water chemistry program in managing the loss of material due to general, pitting and crevice corrosion.

Issue

The LRA proposes to extend the aging management of loss of material due to general, pitting, and crevice corrosion in the steel PWR steam generator shell assembly to other components of the steam generators, in relation with the material, the environment and the aging effect, such as the tube support plate assembly (tube support plate, rods, nuts, etc.), the steam generator main feedwater spray nozzle flanges, the steam generator baffle assemblies, the steam outlet nozzle, the steam generator auxiliary feedwater nozzle thermal sleeves, the steam generator secondary side nozzles and the steam generator secondary manway and handhole opening covers.

In LRA table 3.1.2-1, for these additional components, the applicant considers that these items are consistent with the GALL Report in all aspects (note A), whereas the components are different from the one recommended in the GALL item IV.D2-8.

Moreover, it is not clear to the staff how the one-time inspection program will be implemented for components other than the shell assembly recommended in the GALL Report and how it will be able to adequately detect the aging effect, especially inside the tube bundle in the case of the tube support plate assembly.

Request

Please explain how you will implement the one-time inspection program (NDE techniques, sample, etc.) for steam generator components whose access appears more difficult than for the shell assembly in order to verify the effectiveness of the water chemistry program and the absence of the aging effect of concern.

***Response***

*The CR-3 One-Time Inspection Program is consistent with the program (XI.M32) described in NUREG-1801. As stated on page XI M-105:*

> *One-time inspections may also be used to verify the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation. For example, effective control of water chemistry can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that either verifies that unacceptable degradation is not occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.*

*It further states:*

> *As set forth below, an acceptable verification program may consist of a one-time inspection of selected components and susceptible locations [emphasis added] in the system. An alternative acceptable program may include routine maintenance or a review of repair or inspection records to confirm that these components have been inspected for aging degradation and significant aging degradation has not occurred. One-time inspection, or any other action or program, created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.*

*In addition:*

> *With respect to inspection timing, the population of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function at any time during the period of extended operation. Specifically, inspections need to be completed early enough to ensure that the aging effects that may affect intended functions early in the period of extended operation are appropriately managed. Conversely, inspections need to be timed to allow the inspected components to attain sufficient age to ensure that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the period of extended operation) are identified. Within these constraints, the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation, and in such a way as to minimize the impact on plant operations. As a plant will have accumulated at least 30 years of use before inspections under this program begin, sufficient times will have elapsed for aging effects, if any, to be manifest.*

*All components that are managed by this aging management program become part of the sample. The inspection includes a representative sample of the population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.*

*The steam generators were replaced in the Fall 2009 outage. Since One-Time Inspections are to be completed prior to the end of the current license term (i.e., December 3, 2016), using these locations as part of the sample would not provide the required information on the effectiveness of the Water Chemistry Program. Steam and Power Conversion System components upstream of the steam generators would be preferentially inspected because they would meet the NUREG-1801 requirement to focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The One-Time Inspection Program will provide for specific inspections using tools and techniques that are appropriate for detecting the aging effects of interest.*

*Unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.*

**RAI 3.2-1**

Background

The LRA addresses hardening and loss of strength of external surfaces exposed to air of:

- elastomeric flexible connections due to degradation
- elastomers in expansion joints, piping, piping components, piping elements, and tanks due to degradation,
- PVC or thermoplastic ducting, ducting components, piping, piping components, piping elements and tanks due to elastomer/plastic degradation,
- fiberglass or fiber reinforced plastic piping, piping components, piping elements and tanks due to elastomer/plastic degradation, and
- elastomers in expansion joints, piping, piping components, piping elements, and tanks due to degradation

The LRA acknowledges that aging may occur for this combination of materials and environments and proposes to manage it through the use of its aging management program "External Surfaces Monitoring" (LRA B.2.22).

Issue

In its review of these items, the staff noted that the external surfaces monitoring program contained in the GALL Report is a visual inspection program and that its scope is limited to steel surfaces. The staff also noted that the LRA has committed to enhance its external surfaces monitoring program to include components constructed from materials other than steel and to detect additional aging effects associated with those materials, including hardening and loss of strength. The staff further noted that the LRA has not explicitly committed to enhancing its program to include inspection techniques other than visual inspection. Lastly the staff noted that hardening and loss of strength are not directly detected by visual examinations and that visual changes in elastomers and plastics may, but need not, occur in conjunction with hardening and loss of strength.

Request

Confirm that the enhancements proposed for the External Surfaces Monitoring Program will specifically include physical manipulation and other investigative methods designed specifically to detect hardening and loss of strength in elastomers.

***Response***

*The aging management strategy for elastomers considered that hardening and loss of strength were volumetric attributes that may require physical manipulation and other methods to detect. To that end, the External Surfaces Monitoring Program has been credited with performing visual inspections for attributes that could be detected with visual methods (e.g., cracking, discoloration, fretting, and delamination). In conjunction with the External Surfaces Monitoring Program, CR-3 has specified aging management activities for the inside of elastomeric components that include visual inspection to detect aging effects that are manifest on internal surfaces, as well as physical manipulation and/or testing of volumetric properties. As noted in the response to RAI B.2.23-1 herein, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program augments visual inspections with tests/inspections suitable for detecting the aging effects of interest. For elastomers, this entails physical manipulation and/or testing to verify that hardening and loss of strength have not occurred.*

**RAI 3.2.2.1-1**

Background

The GALL Report, Table 1, indicates that for stainless steels or steels with stainless steel cladding, exposed to reactor coolant, there is a potential for cracking due to cyclic loading (Item IV.C2-26). The aging management program recommended in the GALL Report is ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.

Issue

The LRA indicates that there are stainless steel components (e.g., Reactor Coolant Pressure Boundary (RCPB) piping; Reactor Coolant Pump Safe Ends) that are subjected to the reactor coolant environment. These components do not include the aging effect of cracking due to cyclic loading. It is not clear to the staff why cyclic loading and a corresponding aging management program have not been included for these components.

Request:

Provide additional information indicating why the aging mechanism of cyclic loading is not included for stainless steel components exposed to the reactor coolant environment including Reactor Coolant Pump Safe Ends (RCPB piping), Flow Meter Assembly (RCPB Piping), Hot Leg Surge Line Nozzle (RCPB Piping), Hot Leg Surge Line Nozzle Safe End (RCPB Piping), Surge Line Nozzle Thermal Sleeve (Pressurizer), Spray Line Nozzle Thermal Sleeve (Pressurizer), and the Surge Line Nozzle Safe End (Pressurizer).

***Response***

*The aging effect has been added to the listed components. For the RCPB piping components, the aging effect is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and aligned to IV.C2-26. For the pressurizer components, the aging effect is managed by a combination of the Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Programs and aligned to IV.C2-18.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.2.2.2-1**

Background

On page 3.2-28 of the LRA, in Table 3.2.2-2, for the nickel base alloy core flood tanks in treated water environment, the Nickel-Alloy Commitment is credited to managing cracking due to stress corrosion cracking.

Issue

In LRA, Section A.1.1 and LRA Commitment No. 2, the applicant committed to complying with applicable NRC Orders and implementing applicable bulletins, generic letters, and staff-accepted industry guidelines. Table 3.2.2-2 of the LRA correctly identifies that the GALL Report does not contain any nickel-alloy components in the Engineered Safety Features, Emergency Core Cooling System (PWR) Table (Table V.D1). However, table V.D1 does identify stress corrosion cracking as an aging effect of concern for stainless steel piping managed by the Water Chemistry Program. For other systems in the LRA and GALL Report, management of stress corrosion cracking in nickel-alloy components is managed by the Nickel-Alloy Commitment and various AMPs including the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, Program.

Request

Provide justification and explain how the Nickel-Alloy Commitment provides adequate aging management for the aging effect of cracking due to stress corrosion cracking in nickel base alloy core flood tanks exposed to a treated water environment.

***Response***

*The AMR line in the LRA will be revised to credit the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program in addition to the Nickel-Alloy Commitment and aligned to IV.C2-21. The line rolls up to Table 1 Item 3.1.1-31 with an attendant Note C, 205.*

*The Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the cracking aging effect. The*

*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program has been shown to be effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light water-cooled power plants. In addition, the Nickel-Alloy Commitment ensures that any additional actions deemed necessary are incorporated into the overall aging management strategy.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.2.2.2.3.1-1**

Background

In the GALL Report, Table 2, stainless steel containment isolation piping and components' internal surfaces exposed to treated water are subjected to loss of material due to pitting and crevice corrosion. The aging management programs in the GALL Report recommend to manage this degradation with the Water Chemistry and One-Time Inspection Programs.

Issue

In the LRA, the containment isolation piping and components subjected to treated water item is not listed under stainless steel containment isolation piping and components internal surfaces exposed to treated water in Table 3.2.1 (Item 3.2.1-03). Instead it is listed under stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water in Table 3.2.1 (Item 3.2.1-49). As such, the loss of material due to pitting and crevice corrosion for this component is singularly managed under the Water Chemistry Program. It is not clear to the staff why the proposed program is adequate to manage this particular aging management concern.

Request

Provide additional information on why the use of the Water Chemistry Program without the One-Time Inspection Program is adequate to manage the loss of material due to pitting and crevice corrosion for this aging management issue.

***Response***

*The discussion of Containment Isolation Components in NUREG-1801, Volume 2, Section V.C states that this system consists of isolation barriers in lines for Boiling Water Reactor and Pressurized Water Reactor (PWR) non-safety systems such as the plant heating, waste gas, plant drain, liquid waste, and cooling water systems. CR-3 considered that components addressed in NUREG-1801, Sections V.A (Containment Spray System) and V.D (Emergency Core Cooling Systems) are not consistent with this description and are not intended to be aligned to this item. For safety related Emergency Core Cooling System treated water systems, NUREG-1801 line items for piping and piping components in Sections V.A and V.D specify Water Chemistry only for aging management. Hence, these items were aligned to 3.2.1-49.*

*Containment Isolation Components in non-safety related systems, as described in Section V.C, were associated with their parent systems to ensure appropriate AMPs were assigned. For example, CR-3 considered most waste disposal and drain systems to be raw water applications,* *due to the lack of defined chemistry controls; hence the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was specified to perform recurring inspections versus the use of the One-Time Inspection Program.*

**RAI 3.2.2.2.3.6-1**

Background

In the GALL Report, Table 2, it is indicated that stainless steel piping, piping components, piping elements, and tank internal surfaces exposed to condensation may potentially undergo loss of material due to pitting and crevice corrosion.

Issue

LRA Section 3.2.2.2.3.6 indicated that the reactor building spray piping inside containment is verified drained, not subjected to wetting through system operation, and is kept in standby at ambient conditions. Therefore, it was indicated in the LRA that the reactor building spray piping is not considered susceptible to condensation. It is unclear to the staff how the piping is ensured to be drained and moisture is kept out of it; thus, eliminating the ability for condensation.

Request

Provide additional information regarding how the reactor building spray piping inside containment is ensured to be drained, and how moisture is not allowed to pass through seals into the spray piping.

***Response***

*The CR-3 Reactor Building (RB) Spray System is strictly a standby system. The system design is such that the spray headers in the RB are isolated from the Building Spray pumps by spray header inlet isolation valves, which also function as RB containment isolation valves. These valves are tested under the CR-3 ASME Section XI Inservice Test Program on a quarterly basis. Subsequent to testing the valves, the system is verified drained at the RB penetration by opening local drain valves. In addition to verifying the inlet piping up through the containment penetration drained, the piping inside containment is verified drained as a separate quarterly task.*

*Apart from the Building Spray pump discharge lines, the portion of the RB Spray System inside the RB containment does not have connections with outside water sources and is maintained empty. With no working fluid to alter piping temperature, the spray headers and connected piping inside containment are at ambient temperature and are not expected to experience condensation as a result of temperature differences between system piping surfaces and the RB atmosphere. It is noted that spray header inlet piping up through the containment penetration may be subject to wetting during the course of periodic pump and valve testing. This portion of the Building Spray System has been evaluated as a treated water environment, and is subject to aging management consistent with other wetted portions of the system.*

**RAI 3.2.2.3-1**

Background

LRA Tables 3.2.2-2, 3.2.2-3, 3.3.2-20, 3.3.2-22, 3.3.2-23, 3.3.2-24, 3.3.2-27, 3.3.2-33, 3.3.2-42, 3.3.2-53, 3.3.2-54, 3.3.2-57, 3.4.2-2, 3.4.2-7, 3.4.2-8, and 3.4.2-12 contain items addressing piping insulation exposed to outdoor air and uncontrolled indoor air. The LRA proposes that neither the component nor the material and environment combination is evaluated in the GALL Report (Note J). The LRA further proposes that this combination of environment and material is not subject to aging and that no aging management program is required.

Issue

In its review of these items, the staff noted that depending on the application, piping insulation may be fabricated from many materials. These materials commonly include polymeric foams, inorganic fibers, and solid ceramics. The staff also noted that the applicant did not state the type of insulation which was being used, the material of the pipe over which it was being applied or the range of temperatures expected at the interface between the pipe and the insulation. The staff further noted that some types of insulation, e.g., polymeric foams, are subject to aging and may require aging management. Finally, the staff noted that the combined use of some forms of insulation and piping materials in some environments, e.g., chloride containing insulation over stainless steel pipe in humid environments, may create additional aging effects in the piping material.

Request

Please provide sufficient information concerning: the type of insulation being used; the type of pipe over which it will be applied; the compatibility between the insulation and the pipe; and whether the presence of condensation or other moisture is possible; to allow the staff to conclude whether the insulation is subject to aging or whether the use of the insulation will result in unexpected aging of the pipe material.

***Response***

*The characteristics of thermal insulation are mainly determined by its composition. For that reason, the major types of insulation include fibrous, granular, cellular, and reflective. Inorganic fibers may be glass, rock wool, slag wool, alumina, silica, asbestos, or carbon. Granular insulation is generally calcium silicate. Many mass insulations (e.g., fibrous, granular, or cellular types in rigid, semi-rigid, flexible, blanket/batt, cement, and mastic forms) are produced using two or more of the types listed above to obtain the desired properties. Reflective insulation systems are in most instances made of aluminum or stainless steel. The insulation can be secured with wire, straps, etc. that are typically metal, depending on the chemical atmospheric conditions and the metal/location of the component to which it is affixed. Fasteners may be adhesives or stainless steel skewers, pins, and/or clips. A galvanized wire netting or expanded metal lath may also be used as reinforcement.*

*The types of insulation typically used for nuclear power plant systems include fibrous (e.g., fiberglass, mechanically bonded glass fiber blanket), granular/cellular (e.g., calcium silicate or asbestos), and reflective (e.g., MIRROR). Glass fiber for insulation is usually a pure glass fiber with various types of binders that will absorb and wick water. Calcium silicate is a cementitious* *mixture that readily absorbs and wicks water. Reflective insulation is constructed of layers of aluminum or stainless steel panels with air in between.*

*Degradation of insulation is not an age-related concern, except in outdoor environments due to exposure to sunlight (ultraviolet (UV) radiation) and in instances where plant-specific operating experience has shown exposure to aggressive chemicals, such as sulfur dioxide, in industrial areas and salt air in marine (seashore) areas.*

*At CR-3, depending on the specific service, the following insulation material is applicable to systems within the scope of license renewal:*

- *Mineral Fiber*
- *Calcium Silicate*
- *Fiberglass*
- *Elastomeric Foam*
- *Glass Wool*
- *Stainless Steel Reflective*

*Insulation jacketing, where required, is stainless steel or aluminum with polyethylene and Kraft paper moisture barrier.*

*Air-Indoor Uncontrolled Service Environment*

*The insulation and insulation jacketing materials do not require an aging management program because these insulation materials are exposed to indoor air environment. In this environment, these materials have no aging effects requiring management. The operating experience review specifically considered plant-specific information related to the effects of aging on insulation materials. That review confirmed that no aging effects requiring management are applicable to the insulation materials that are subject to the AMR at CR-3.*

*Air-Outdoor Service Environment*

*The LRA specified this environment for the Appendix R Chilled Water System and the Emergency Feedwater System. Upon further review, the Emergency Feedwater System does not have insulation in this environment.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

*The insulation associated with the Appendix R Chilled Water System components is located on the Machine Shop roof. Since the insulation is jacketed, it is not exposed to UV and its configuration precludes the concentration of contaminants, there are no aging effects. The operating experience review specifically considered this environment. That review confirmed that no aging effects requiring management are applicable to the insulation materials that are subject to the AMR at CR-3.*

*The prevention of condensation is addressed in CR-3's insulation specification. For example:*

> *This insulation shall be 3/4-inch thick and will be used to prevent surface condensation.*

*In addition, pipe hangers on pipes operating at temperatures below ambient air temperature are insulated to prevent condensation or frosting.*

*Section 5.2.2.6 of the CR-3 Final Safety Analysis Report (FSAR) provides a discussion of component and piping insulation as it relates to the compatibility of insulation to the underlying component. It states:*

*a. Reactor Building*

*When CR3 was built, all component and piping insulation was supplied by Transco, Inc., and it was either "reflective" or "totally encapsulated" insulation. Each batch of the encapsulated insulation was tested for the following:*

| | | |
|---|---|---|
| a. | Chloride (leachable) | 10 PPM * |
| b. | Sodium (leachable) | 133 PPM * |
| c. | Silicate (leachable) | 0.5 PPM * |
| * Represents values for a typical analysis. | | |

*Changes have occurred in the insulation within the reactor building through the years.*

*NUKON has been substituted for Transco reflective piping insulation in the reactor building for new and existing applications. NUKON is approved for use on piping and equipment inside containment areas as described in Owens-Corning Fiberglass Topical Report OCF-1. Tests on NUKON material for chlorides, sodium, silicate, and fluorides exhibit results well within the acceptable analysis range identified in Regulatory Guide 1.36, Figure 1.*

*Armstrong "Armaflex," a flexible elastomeric thermal insulation, is installed on supply and return piping of the Nuclear Services Closed Cycle Cooling System (SW) to the three Reactor Building fan coolers. Armaflex is also installed on SW piping to and from the Letdown Coolers. The Armaflex was installed due to excessive sweating of the SW lines. This insulation has been evaluated to determine its capability to withstand LOCA conditions within the reactor building and to determine its potential to block the Reactor Building Sump screen if it were to be blown off the SW piping and is acceptable for this application.*

*b. Outside of the Reactor Building*

*The balance of plant insulation (Forty-Eight Insulation, Inc., type MF pipe insulation) was supplied by Anco. This mineral fiber insulation contains less than 20 ppm leachable chloride.*

*Blanket type insulation (Enclosed Fiberglass) similar to Owens-Corning "Nukon" may be used as replacement insulation for the Mineral Fiber insulation outside of the Reactor Building.*

*Section 4.2.2.7 of the FSAR specifically addresses Reactor Coolant (RC) System equipment insulation. It states:*

*The RC system components are insulated with stainless steel reflective insulation. The insulation on the reactor vessel is shown in Figure 4-4.*

*The insulation units on all RC system components are designed for ease of removal and installation in such areas as seam welds, nozzles, and bolted closures. The insulation units permit free drainage of any condensate or moisture from within the insulation unit.*

*The RC system equipment insulation is all metal reflective insulation made of austenitic stainless steel, which is compatible with the RC system pressure boundary materials.*

*In the event of reactor coolant leakage, all stainless steels and Inconel materials are compatible with the resulting environmental atmosphere and no effective corrosion is expected.*

*In conclusion, the insulating materials used at CR-3:*

- *are typical of those used throughout the industry,*
- *in the environments of interest, operating experience has determined that there are no aging effects requiring management; and*
- *the design and installation of the insulation has accounted for the possibility of condensation and piping system leakage.*

**RAI 3.3.2.2-1**

Background

Atmospheric chloride is known to induce various degradation mechanisms, which can affect the lifetime of stainless steel materials. These degradation mechanisms include pitting, crevice corrosion, and stress corrosion cracking. Locations near the coast will have much higher concentration of chloride aerosol particles in the air and a higher susceptibility towards these various degradation mechanisms.

Issue

In the LRA, various tables including but not limited to Table 3.3.2-2, Table 3.3.2-10, and Table 3.3.2-12, indicate that components are subjected to uncontrolled air. These components are listed as having no degradation mechanisms and as such require no aging management program. It is unclear to the staff how the chlorides from the coast are removed from the uncontrolled air source so that the aging mechanisms associated with chloride aerosols do not need to be evaluated.

Request

Provide additional information that will highlight why degradation mechanisms associated with chloride aerosols (i.e., pitting, crevice corrosion, stress corrosion cracking) do not need to be evaluated for stainless steel materials in uncontrolled air environments.

***Response***

*The CR-3 License Renewal methodology utilized NUREG-1801 environment definitions as noted in LRA Table 3.0-1, Service Environments.*

*NUREG-1801, Table IX.D, defines Air-Indoor Uncontrolled as, "Indoor air on systems with temperatures higher than the dew point, i.e., condensation can occur but only rarely, equipment surfaces are normally dry."*

*NUREG-1801, Table IX.D defines Air-Outdoor as, "The outdoor environment consists of moist, possibly salt-laden atmospheric air, ambient temperatures and humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions, including salt water spray, where applicable. A component is considered susceptible to a wetted environment when it is submerged, has the potential to pool water, or is subject to external condensation."*

*The AMR methodology at CR-3 includes use of OE to confirm the set of aging effects that had been identified through material/environment evaluations. Progress Energy procedures directing system/component monitoring and trending require that System Health reports be maintained, and that periodic updates be performed to capture relevant plant and industry OE, regulatory correspondence, technical issues, etc. System Heath reports were reviewed for relevant OE in the development of AMRs to ensure that the set of aging effects identified was comprehensive. Progress Energy procedures direct an ongoing review of OE and require that OE be screened and evaluated for site applicability.*

*OE screened as applicable is captured in the Corrective Action Program for follow-up and resolution. CR-3 AMR methodology incorporated a review of OE items identified as applicable to CR-3, addressing a review of at least the prior five to ten years, consistent with the recommendations of Nuclear Energy Institute NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR 54 – The License Renewal Rule." These searches were facilitated by CR-3 License Renewal database queries using key words to identify aging effects and mechanisms. The review of OE did not identify that pitting and crevice corrosion, and stress corrosion cracking (SCC) of external surfaces of stainless steel in an indoor environment is an aging concern at CR-3.*

*The CR-3 License Renewal AMR methodology was based on mechanistic determinations and OE, with consideration given to relevant aging effects identified in NUREG-1801, Volume 2 tables. The methodology specifically addressed the aging effects identified in NUREG-1801 for environments associated with external surfaces.*

*Electric Power Research Institute (EPRI) Technical Report 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," Revision 4, discusses stainless steel in an external surface environment and states that:*

> *SCC of stainless steels exposed to atmospheric conditions and contaminants is considered plausible only if the material temperature is above 140°F. In general, SCC very rarely occurs in austenitic stainless steels below 140°F [D. Peckner and I. M. Bernstein, Eds., Handbook of Stainless Steels, McGraw-Hill, New York, 1977, and Metals Handbook, Ninth Edition, Volume 13, "Corrosion," American Society of Metals International, Copyright 1987].*

*Although SCC has been observed in systems at lower temperatures than this 140°F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. Additionally there does not appear to be a threshold level of stress for SCC, with the stress level merely dictating the time to failure. However, if stainless steel is known not to be sensitized, then SCC of the material need not be considered an applicable aging effect in an atmospheric environment. There is data indicating that as-welded Types 304 and 316 resisted SCC, which provides an indication that sensitization does not always lead to SCC. When considering the stainless steel cracking logic, SCC may be assumed for high carbon content stainless steels such as Type 304 and 316, but not for low carbon content stainless steels such as Type 304L and 316L. Therefore, SCC of stainless steel is not a concern in buried or indoor environments but may be a concern in continuously or frequently wetted locations in outdoor environments if temperatures are >140°F, or if plant operating experience shows exposure to salt air (e.g., seashore areas) or other aggressive species (e.g., sulfur dioxide or acid rain in industrial areas).*

*Indoors, crevice corrosion is a concern in locations of frequent or prolonged wetting, or of alternate wetting and drying. Outdoors, precipitation tends to wash a surface rather than concentrate contaminants and, as such, crevice corrosion may be a concern for only plants whose operating experience has shown surface exposure to an aggressive species (such as salt air, sulfur dioxide, and acid rain).*

*On the exterior surfaces of the mechanical equipment addressed by this tool, pitting is a significant aging effect for carbon and low-alloy steels, cast irons, stainless steels, nickel-base alloys, and aluminum and aluminum alloys exposed to weather (outdoors) when plant operating experience has shown a corrosive (aggressive) ambient environment (such as salt air, acid rain, or sulfur dioxide) in marine (seashore) or industrial areas.*

*The preceding discussion in the EPRI document identifies the potential for corrosion of stainless steel in outdoor environments where exposure to a seashore environment exists. It does not identify a concern with corrosion of stainless steel in an indoor environment in the context of these discussions. Plant OE reviews support the conclusion that these aging mechanisms are not a concern in a CR-3 indoor environment.*

*Based upon the review of plant-specific OE, NUREG-1801 definitions and aging effect assignments, and industry literature, degradation mechanisms associated with prolonged contact with chloride aerosols (e.g., pitting and crevice corrosion and cracking) were not assigned to stainless steel components in a CR-3 indoor environment.*

**RAI 3.3.2.21-1**

Background

On page 3.3-188 of the LRA in Row 2 of Table 3.3.2-21, the nickel base alloy cooler tubes exposed to treated water are managed by the Water Chemistry Program.

Issue

The GALL Report recommends the use of the Water Chemistry Program and the One-Time Inspection Program to manage this aging issue (GALL Report, Item V.A-16). The One-Time Inspection Program provides measures to verify the effectiveness of the Water Chemistry Program. It is not clear how the Water Chemistry Program alone provides adequate aging management for this aging effect in these components.

Request

Provide a detailed technical justification of why the One-Time Inspection Program is not needed to verify the effectiveness of water chemistry control in managing the aging effect of reduction of heat transfer effectiveness due to fouling of heat transfer surfaces in these nickel base alloy components.

***Response***

*The One-Time Inspection Program has been added to the Water Chemistry Program for the AMR line item in question. In addition, it has been determined that the Raw Water environment is applicable for Sample Cooler CAHE-6 (Drawing 302-700-LR, Sheet 1 Coordinate C7) and its associated piping, since they communicate with the RB Sump. The associated aging effects for the stainless steel material (cracking due to SCC; loss of material due to crevice corrosion, microbiologically influenced corrosion (MIC), and pitting corrosion) are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The affected component/commodities include the Containment Isolation Piping and Components on LRA Page 3.3-186 and the Piping, piping components, piping elements, and tanks on LRA Page 3.3-190. The same aging effects are applicable to the nickel base alloy material of the Post-Accident Sampling System (PASS) Sample Cooler Components on LRA Page 3.3-187 that are also managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The aging effect of reduction of heat transfer effectiveness due to fouling of heat transfer surfaces of the nickel base alloy PASS Sample Cooler Tubes (LRA Page 3.3-188) is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.3.2.28-1**

Background

LRA Tables 3.3.2-28 and 3.3.2-36 addressed the loss of preload of carbon or low alloy steel/ stainless steel closure bolting in the fuel oil system and fire protection system, respectively, of the auxiliary systems, which are exposed to soil (outside). The LRA stated that the aging effect of the AMR items is due to thermal effects, gasket creep and self-loosening and no Table 1 item is related with the AMR items. The consistency note that the applicant claimed for the AMR items was Note J, which means neither the component nor the material environment combination are evaluated in the GALL Report.

Issue

In relation to the closure bolting items exposed to soil, the staff noted that the LRA did not provide detailed information on how the Bolting Integrity Program manages the loss of preload and loss of material of the buried closure bolting components especially in terms of the inspection extent and schedules. The staff also found a need to review relevant operating experience regarding the loss of preload and loss of material of the buried closure bolting components and associated leakage.

Request

1. Describe how the Bolting Integrity Program manages the loss of preload and loss material of the buried closure bolting components including the inspection extent and schedule.

2. Clarify whether the bolts exposed to soil are coated.

3. Provide operating experience regarding the loss of preload and loss of material of the buried closure bolting and associated leakage as relevant.

***Response***

*The Bolting Integrity Program is credited with managing Loss of Preload due to Thermal Effects, Gasket Creep, and Self-loosening in buried bolting in Tables 3.3.2-28 and 3.3.2-36. This is accomplished consistent with the recommendations of NUREG-1801 through controls on materials selection, utilizing NUREG-1339-endorsed guidance on design and installation of bolted connections, control of lubricants, etc.*

*The Buried Piping and Tanks Inspection Program, rather than the Bolting Integrity Program, is credited with managing loss of material of buried bolting in Tables 3.3.2-28 and 3.3.2-36 (denoted by closure bolting line items in a "soil" environment). Piping specifications required buried Fire Protection System bolted connections to be coated with a corrosion inhibitor subsequent to installation and prior to backfilling. The fuel oil storage tanks were coated at the factory, and the tank vendor drawing shows that additional bitumastic coating was supplied with the tanks for field touchup upon installation at CR-3. Additionally, the fuel oil storage tanks are protected from corrosion with an impressed current cathodic protection system.*

*The Fuel Oil Storage Tanks and buried Fire Protection System piping are subject to the inspection requirements of the Buried Piping and Tanks Inspection Program. The program provides for as-found pipe coating and material condition inspection whenever buried components within the scope of this License Renewal program are exposed, with an overall frequency of inspections not to be less than one each 10 years, consistent with the recommendations of NUREG-1801.*

*Additionally, Fire Protection System buried piping integrity is routinely verified through monitoring of system pressure and jockey pump operation. Fuel Oil System buried bolting is limited to several flanged connections at the underground fuel oil storage tanks (buried fuel oil piping is socket welded). The fuel oil storage tanks are regularly monitored, and fuel oil quality is subject to regular sampling and analysis to detect contamination, including water contamination through groundwater intrusion.*

*The CR-3 AMR process for identifying applicable aging effects utilized mechanistic determinations based on the EPRI Mechanical Tools, review of industry and plant OE, and consideration of potential aging effects identified in NUREG-1801. Loss of Preload due to Thermal Effects, Gasket Creep, and Self-loosening of buried bolted connections was not identified in CR-3 OE reviews, nor is it considered an applicable aging effect in the topical presentation in the EPRI Mechanical Tools. Rather, this aging effect was included in the Fire Protection and the Fuel Oil Systems AMRs to address its presence in NUREG-1801.*

*A review of plant OE did identify an instance wherein fuel oil sampling activities identified potential water intrusion in Fuel Oil Storage Tank DFT-1A. Subsequent investigative activities included disassembly of the manway flanged connections, which are not buried, but are located above the tank in an access pit. Inspection of the gasket flange faces, showed no evidence of leakage, and the manway was reassembled with new gaskets. While the source of the water identified was not ascertained, no additional indications of water intrusion were noted. It was reasoned that the previous indications of water intrusion may have been due to undetected water during a fuel delivery or to leakage of water that had seeped into the access pit through the gasket on the manway cover.*

**RAI 3.3.2.33-1**

Background:

GALL AMP, XI.M36 titled "External Surface Monitoring Program," is a condition monitoring program. It focuses to have inspectors visually identify general corrosion aging effects in steel and other ferrous materials. It notes that general corrosion can also manifest itself as a byproduct (e.g., discoloration or coating degradation) of other forms of corrosion, e.g., pitting and crevice. This AMP, however, does not address galvanic corrosion. There is no discussion in the Scope of Program, whether this form of corrosion can manifest itself as a byproduct for general corrosion.

Issues:

The GALL Report, in Auxiliary Systems for piping, piping components, and piping elements, identifies an aging effect of concern of loss of material due to general, pitting, and/or crevice corrosion. For items in the LRA, however, galvanic corrosion is identified as the aging mechanism of interest. This mechanism is rooted in the interaction of the two dissimilar metals with different potentials when placed in electrical contact in an electrolyte. The effects of this mechanism may not be as visible and detectable as that of general corrosion, especially when the adjacent dissimilar metals exhibit a small differential in electrical potentials.

Request:

How will the aging effects of loss of material due to galvanic corrosion of external surfaces be managed?

***Response***

*CR-3 has identified galvanic corrosion as an applicable aging mechanism in outdoor locations where the potential exists for carbon steel/cast iron to be in contact with stainless steel in an* *environment that may be wetted (weather). In these instances, the carbon steel/cast iron is anodic to the stainless steel, and may be susceptible to galvanic corrosion should unfavorable area ratios exist. The resulting corrosion of carbon steel/cast iron would be evidenced by iron oxide (rust) on external surfaces of the corroding component. If the formation of corrosion on external surfaces is so slight as to be imperceptible (whether due a small difference in electrical potential or to lack of an unfavorable ratio of cathodic to anodic material), it follows that the loss of material is likewise insignificant and does not pose a liability to the component's intended function.*

**RAI 3.3.2.36-1**

Background

LRA Table 3.3.2-36 contains items which address hardening and loss of strength due to elastomer/plastic degradation of PVC or thermoplastic piping, piping components, standpipes, hydrants and tanks exposed to fire water. The applicant proposes that neither the component nor the material and environment combination is evaluated in the GALL Report (Note J). The applicant acknowledges that aging may occur for this combination of materials and environments and proposes to manage it through the use of its aging management program "Fire Water System" (LRA B.2.14).

Issue

In its review of these items, the staff noted that hardening and loss of strength of PVC and thermoplastics are not directly detected by visual examinations and that visual changes in elastomers and plastics may, but need not, occur in conjunction with hardening and loss of strength. The staff also noted that hardening and loss of strength of PVC and thermoplastic materials need not be accompanied by a change in wall thickness. The staff further noted that the fire water system aging management program contained in the GALL Report is designed to detect changes in pipe wall thickness through visual inspections and other means but does not contain any test method which will directly assess hardening or loss of strength.

Request

Justify how the proposed aging management program will detect changes in hardness and strength of the plastic components under consideration or propose an aging management program which will directly measure these changes.

***Response***

*The subject polyvinyl chloride (PVC) piping is not supplied by the CR-3 Fire Services System, but, rather, is part of the Fire Protection System associated with adjacent Unit 1 and Unit 2 fossil plants. It was included in License Renewal scope based on continuing the scoping boundaries of the CR-3 Fire Services System to include connected buried piping, in order to ensure the effects of aging wouldn't compromise the system pressure boundary in the event of a leak. However, in reviewing this item, it was noted that the connected Unit 1 & 2 piping is isolated from CR-3 Fire Services System piping by normally closed isolation valve FSV-25, as well as check valve FSV-26; such that a failure of the Unit 1 & 2 piping would not result in a loss of CR-3 fire water inventory (Reference: License Renewal Boundary Drawings 302-231-LR, sht. 2 and* *sht. 4). This piping connection is not required by the CR-3 current licensing basis to contribute to the credited inventory of firewater. As such, the piping beyond FSV-26 performs no intended function and is determined not to be in the scope of License Renewal. The AMR line items and AMP requirements associated with PVC piping in the connected Unit 1 & 2 Fire Protection piping are therefore not applicable and are deleted from the CR-3 LRA.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.3.2.36-2**

Background

LRA Table 3.3.2-36 contains items which address PVC or thermoplastic piping, piping components, standpipes, hydrants and tanks exposed to soil. The applicant proposes that neither the component nor the material and environment combination is evaluated in the GALL Report (Note J). The applicant further proposes that this combination of environment and material is not subject to aging and that no aging management program is required.

Issue

In its review of these items, the staff noted that there are many polymeric materials which fall within the definition of "PVC and thermoplastics". The staff also noted that it is unlikely that all the materials within this class of materials will respond in the same manner to exposure to soil and ground water.

Request

Identify the specific material or materials in use and justify why these materials do not experience aging when exposed to soil or ground water or, alternatively, propose an aging management program to manage the aging of these materials.

***Response***

*As stated in the response to RAI 3.3.2.36-1 above, the subject PVC piping has been determined to perform no intended function and is not in the scope of License Renewal. The associated AMR line items are therefore not applicable and are deleted from the CR-3 LRA.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.3.2.36-3**

Background

On page 3.3-284 of the LRA, in Table 3.3.2-36, the AMR result for steel components in fuel oil environment with an aging effect of loss of materials due to MIC indicates that the Fire Protection and Fuel Oil Chemistry AMPs are credited.

Issue

The GALL Report recommends the use of the Fuel Oil Chemistry Program and the One-Time Inspection Program to manage the aging effect of loss of materials due to microbiologically influenced corrosion for steel components in a fuel oil environment (GALL Report, Item VII.H1-10). The One-Time Inspection Program provides measures to verify the effectiveness of the Fuel Oil Chemistry Program. It is not clear how the Fire Protection Program and the Fuel Oil Chemistry Program provide adequate aging management for this aging effect in these components.

Request

Provide a detailed technical justification of why the One-Time Inspection Program is not needed to verify the effectiveness of fuel oil chemistry control in managing the aging effect of loss of materials due to microbiologically influenced corrosion in the identified components.

***Response***

*The Fire Protection Program and the Fuel Oil Chemistry Program were originally assigned to manage the Diesel Fire Service Pump fuel oil supply lines with component/commodity title "Piping, piping components, standpipes, hydrants, and tanks" identified on LRA page 3.3-284. LRA Page 3.3-284 identifies that for these piping components GALL, alignment was made to VII.G-21 (A-28), which recommends the Fire Protection and the Fuel Oil Chemistry Programs to manage loss of material due to general, crevice, and pitting corrosion in piping components made of steel in a fuel oil environment.*

*However, LRA page 3.3-284 will be revised to identify that carbon or low alloy steel "Piping, piping components, standpipes, hydrants, and tanks" located in a fuel oil environment, with aging effects/mechanisms of general, crevice, and pitting corrosion, MIC, and fouling will be managed by the Fire Protection Program, Fuel Oil Chemistry Program, and the One Time Inspection Program.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI 3.3.2.49-1**

Background

LRA Table 3.3.2-49 addresses hardening and loss of strength due to degradation of external surfaces of elastomers in expansion joints exposed to uncontrolled indoor air. The applicant proposes to manage this aging process through the use of its aging management program "Open Cycle Cooling Water System" (LRA B.2.10). The LRA proposes that neither the component nor the material and environment combination being considered is included in the GALL Report (Generic Note J).

Issue

In its review of Table 3.3.2-49, the staff noted that the LRA AMP "Open Cycle Cooling Water System" has been enhanced from the corresponding GALL AMP to include periodic maintenance of nuclear services and decay heat seawater expansion joints. The staff also noted that the Open Cycle Cooling Water System AMP relies on procedures established by Generic Letter 89-13 and that this Generic Letter only addresses issues associated with the interaction of the inner surface of pipes and service water. The staff further noted that neither the Open Cycle Cooling Water System AMP nor the Generic Letter contain test methods suitable for identifying hardening or loss of strength of elastomers. Given that the external surfaces of elastomer expansion joints are not within the scope of the Open Cycle Cooling Water System AMP and given that this AMP does not contain appropriate test methods for detecting hardening or loss of strength of elastomers, the staff is unsure how this AMP will adequately manage the aging effect in question. The notes that the LRA has proposed to use the External Surfaces Monitoring AMP (LRA B.2.22) to manage aging for elastomers in other piping systems.

Request

Explain why it is appropriate to use the proposed AMP to manage aging and how the proposed AMP will adequately accomplish that task.

***Response***

*The CR-3 aging management strategy for elastomers considers that hardening and loss of strength of elastomers is a volumetric property that might not be detectable with visual inspection alone. For Nuclear Service and Decay Heat Sea Water System expansion joints in Table 3.3.2-49, the Open Cycle Cooling Water System includes periodic preventive maintenance activities that incorporate visual inspections of external and internal surfaces, as well as durometer testing to verify hardening and loss of strength have not occurred.*

**RAI 3.4.2.1-1**

Background

The GALL Report indicated in Table 4, line item 33, that stainless steel heat exchanger components exposed to raw water may undergo loss of material due to pitting, crevice, and microbiologically influenced corrosion, and fouling. In Table 4, line item 34, the GALL Report indicates that steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water may undergo reduction of heat transfer due to fouling. The GALL Report further suggests that this degradation mechanism can be managed by the Open-Cycle Cooling Water System Program.

Issue

In LRA Table 3.4.2-1, it is indicated that the loss of material due to pitting, crevice corrosion, and MIC of stainless steel piping, piping components, piping elements, tanks, and condenser vacuum pump heat exchanger exposed to raw water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. It is not clear to the staff how this aging management program will be able to address this aging issue.

Request

Provide additional information indicating how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for managing loss of material of stainless steel exposed to raw water.

**Response**

*As described in the CR-3 AMP basis documents and LRA page B-37, the Open Cycle Cooling Water System (OCCW) Program at CR-3 addresses the Nuclear Service and Decay Heat Seawater System and the safety-related heat loads and piping components from various systems it services. Nonsafety-related components and heat loads are not included in this program unless they are considered to directly support the intended function of safety-related components in the program. The CR-3 OCCW Program addresses elements of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," relating to safety-related open cycle cooling water systems.*

*LRA Table 3.4.2-1 evaluates nonsafety-related components in the Condenser Air Removal System. Based on the NUREG-1801 description of the OCCW Program as well as the CR-3 methodology, the Condenser Air Removal System components did not fit the requirements to be managed by the Open Cycle Cooling Water System Program.*

*The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will utilize established non-destructive examination techniques that are performed by qualified personnel in accordance with site-controlled procedures and processes to determine loss of material due to pitting and crevice corrosion and MIC of stainless steel piping, piping components, piping elements, tanks, and condenser vacuum pump heat exchangers exposed to raw water. This program will utilize testing methods suitable to detect the applicable aging effects that could challenge the pressure boundary intended function. This program will take corrective actions prior to the loss of component intended function as detailed in NUREG-1801, Item XI.M38. Additional details in this program's management of stainless steel are provided in the response to RAI B.2.23-1.*

*Based on above, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for managing loss of material of stainless steel exposed to raw water in the Condenser Air Removal System.*

**RAI 3.4.2.2-1**

Background

In the GALL Report, Table 4 indicates that steel piping, piping components, and piping elements exposed to steam for the steam and power conversion system can be subject to loss of material due to general corrosion. The GALL Report suggests managing this degradation using a Water Chemistry Program and a One-Time Inspection Program.

Issue

In the LRA, various carbon or low alloy steel components for the steam and power conversion system are subjected to an environment of steam and may undergo general corrosion. The aging management program for this material aging process is Water Chemistry Program. It is not clear to the staff how the use of a Water Chemistry Program alone is consistent with the GALL Report and will be able to manage this aging issue.

Request

Provide additional information on why a One-Time Inspection Program is not necessary to manage the general corrosion of carbon or low alloy steel components in the steam and power conversion system.

***Response***

*NUREG-1801, Item VIII.B1-8, does not predict general corrosion of carbon steel in high purity, low dissolved oxygen steam systems. CR-3 included this aging mechanism based on its utilization of the EPRI Mechanical Tools in AMRs. CR-3 considers that the same AMP that NUREG-1801 recommends to manage pitting and crevice corrosion in this service condition is also acceptable to manage general corrosion. AMR items that are aligned to NUREG-1801, Item VIII.B1-8, only specify the Water Chemistry Program for aging management. The CR-3 Water Chemistry Program is an existing program that relies on monitoring and control of water chemistry to keep contaminants below specified limits.*

*A site OE review of the Main Steam System, Auxiliary Steam System, and Gland Steam System was performed by License Renewal personnel during the License Renewal AMR process. CR-3 OE reviews have not identified general corrosion of carbon steel as applicable in internal surfaces of Main Steam System, Auxiliary Steam System, and Gland Steam System piping components. (Note that many Main Steam System, Auxiliary Steam System, and Gland Steam System components are ultrasonically tested periodically for flow-accelerated corrosion by the CR-3 Flow-Accelerated Corrosion Program.)*

*Based on a review of CR-3 steam system OE, and NUREG-1801 guidance, the CR-3 License Renewal methodology followed the NUREG-1801 program recommendations in the treatment of steam for the Main Steam System, Auxiliary Steam System, and Gland Steam System piping components. Accordingly, the Water Chemistry Program alone will adequately manage general corrosion of steel piping components exposed to steam in the Main Steam System, Auxiliary Steam System, and Gland Steam System.*

**RAI 3.4.2.2.3-1**

Background

In the GALL Report, Table 4, steel piping, piping components, and piping elements exposed to raw water in the steam and power conversion system are subjected to possible loss of material from general corrosion, pitting, crevice corrosion, MIC, and fouling. The recommended aging management program is suggested as being plant specific.

Issue

LRA, Section 3.4.2.2.3 indicated that there is no steel piping or piping components exposed to raw water, so the aging mechanisms in this environment does not need to be considered. However, in Table 3.4.2-1, the piping, piping components, piping elements, and tanks are identified as a carbon or low alloy steel in an environment of raw water.

Request

Provide additional information on why Section 3.4.2.2.3 of the LRA indicates that there is no steel piping exposed to raw water, whereas Table 3.4.2-1 indicates the opposite.

***Response***

*Table 3.4.2-1 identifies Condenser Air Removal System piping, piping components, piping elements, and tanks made of carbon or low alloy steel, on LRA Page 3.4-34, and gray cast iron, on LRA Page 3.4-35, in an environment of raw water and subject to general, crevice, and pitting corrosion.*

*These Table 3.4.2-1 line items reflect piping components in the Condenser Air Removal System that assist in maintaining a vacuum in the Main Condenser. This piping has a saturated air internal environment, but was evaluated as raw water for the purposes of generating a bounding set of aging effects. These piping components were rolled up to Table 3.4.1, line item 3.4.1-30, on LRA Page 3.4-29, which reflects an environment of air with internal condensation, which is appropriate for the design of this system.*

**RAI 3.4.2.2.8-1**

Background

The GALL Report in relevant table rows describe that it is possible to have MIC occurring in stainless steel piping, piping components, piping elements, and other plant components when exposed to contaminants in lubricating oil. GALL Report XI.M39 AMP titled "Lubricating Oil Analysis Program," relies on the periodic sampling and analysis of lubricating oil to maintain contaminants to within acceptable limits, thereby minimizing the exposure of stainless steel to a corrosive environment.

Issue

LRA Section 3.4.2.2.8, titled "Steam and Power Conversion System Stainless Steel Piping, Piping Components, and Piping Elements and Heat Exchanger Components Exposed to Lubricating Oil," states that CR-3 does not take steps to predict MIC in lubricating oil systems, unless indicated by operating experience. Microbacterial growth could be prominent in aqueous and oil exposed environments. The staff identified instances of operating experience where water had infiltrated CR-3's lubricating oil environment. Early detection of MIC is crucial to assure the prevention of SSC failures. Although the GALL Report for this program accepts the one-time inspection of selected components at susceptible locations to be an acceptable method to ensure that corrosion has not occurred, it does not provide for a continuous monitoring of the lubricant and/or SSCs to determine if alert limits in physical and chemical characteristics, and trends in biological growths have been reached (see program Element 5, monitoring and trending).

Request

What kind of testing/inspection measures, does CR-3 use to identify, curb/mitigate, and manage aging effects due to MIC?

For the impacted environments (accumulated water in sumps, etc.), please provide the frequency, location of sampling and identify what are the monitored parameters.

***Response***

*The CR-3 Lubricating Oil Analysis Program routinely monitors lubricating oil for the presence of water and particulates, consistent with the program requirements described in NUREG-1801, Volume 2, Section XI.M39. CR-3 considers that water and particulate contamination are not only inherently adverse to the lubricating properties of oil, but may be a precursor to a range of potential problems, including, but not limited to, forms of corrosion such as MIC. Under the Lubricating Oil Analysis and the CR-3 Corrective Action Program, levels of water content or particulates that might be indicative of lubricating oil breakdown or equipment wear would be subject to further investigation to determine the cause and appropriate corrective/mitigative actions. There is no predetermined recourse associated with lubricating oil analysis results that exceed predetermined limits. Rather, these are specified as applicable based on consideration of a range of factors, such as the particular limit(s) exceeded, system configuration, operating requirements, etc. As a specific example, CR-3 has performed testing of bacteria counts in the past during the course of resolving concerns regarding water content in the Turbine Lube Oil System, with the test results substantiating that MIC was not active.*

**RAI 3.4.2.3-1**

Background

LRA Table 3.4.2-3 contains items which address hardening and loss of strength due to elastomer/plastic degradation of fiberglass or fiber reinforced plastic piping, piping components, piping elements and tanks exposed to outdoor air. The applicant proposes that neither the component nor the material and environment combination is evaluated in the GALL Report (Note J). The applicant acknowledges that aging may occur for this combination of materials and environments and proposes to manage it through the use of its aging management program "External Surfaces Monitoring" (LRA B.2.22).

Issue

In its review of these items, the staff noted that the external surfaces monitoring program contained in the GALL Report is a visual inspection program and that its scope is limited to steel surfaces. The staff also noted that the applicant has committed to enhance its external surfaces monitoring program to include components constructed from materials other than steel and to detect additional aging effects associated with those materials, including hardening and loss of strength. The staff further noted that the applicant has not explicitly committed to enhancing its program to include inspection techniques other than visual inspection. Lastly the staff noted that hardening and loss of strength are not directly detected by visual examinations and that visual changes in elastomers and plastics may, but need not, occur in conjunction with hardening and loss of strength.

Request

Justify how the proposed aging management program will detect changes in hardness and strength of the plastic components under consideration or propose an aging management program which will directly measure these changes.

***Response***

*The aging management strategy for fiberglass and plastics considered that hardening and loss of strength were volumetric attributes that may require physical manipulation and other investigative methods to detect. To that end, the External Surfaces Monitoring Program has been credited with performing visual inspections for attributes that could be detected with visual methods (e.g., cracking, crazing, chalking, discoloration, fretting, delamination). In conjunction with the External Surfaces Monitoring Program, CR-3 has specified aging management activities for the inside of fiberglass and plastic components that include visual inspection to detect aging effects that are manifest on internal surfaces, as well as physical manipulation and/or testing of volumetric properties. As noted in the response to RAI B.2.23-1 herein, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program augments visual inspections with tests/inspections suitable for detecting the aging effects of interest. For fiberglass and plastics, this entails physical manipulation and/or testing to verify that hardening and loss of strength have not occurred.*

**RAI 3.4.2.4-1**

Background

The GALL Report indicated in Table 4, line item 16, that stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water may undergo loss of material due to pitting and crevice corrosion. The GALL Report further suggests that this degradation mechanism can be managed by the Water Chemistry and One-Time Inspection Programs.

Issue

In the LRA, Table 3.4.2-4, it is indicated that the loss of material due to pitting and crevice corrosion of stainless steel piping, piping components, piping elements, tanks, and containment isolation piping and components exposed to treated water is not evaluated in the GALL Report. There are other similar components found in the LRA Table 3.4.2-7. The applicant indicates that these aging effects will be managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components program. It is not clear to the staff why the proposed program is adequate to manage this particular aging management concern.

Request

Provide additional information indicating why the Internal Surfaces in Miscellaneous Piping and Ducting Components is adequate to manage loss of material due to pitting and crevice corrosion for stainless steel components exposed to treated water.

***Response***

*LRA Table 3.4.2-4 identifies components in the OTSG Chemical Cleaning System, used for wet layup or chemical cleaning of the OTSGs. This system provides piping/connections to allow for wet layup or chemical cleaning of the OTSGs, but it does not function during normal operating modes. When wet layup or chemical cleaning is to be performed, connections are made to the OTSG through containment piping penetrations. If, and when, a decision is made to chemically clean the OTSGs, temporary piping, valves, tanks, and pumps may also be utilized in the RB to connect the system to the OTSGs. Only permanently installed portions of the system are included in the scope of License Renewal. Since most of the system in question is operated only periodically, the system is not under continuous chemistry control and monitoring. Because of the system's operating characteristics, the Water Chemistry and One Time Inspection Programs are not suitable to manage these aging effects/mechanisms.*

*LRA Table 3.4.2-7 identifies evaluation of components in the Emergency Feedwater System, which is under continuous Chemistry control and monitoring.*

*Due to the system's operating characteristics, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen to age-manage the subject components. This is a new program that will be implemented via existing preventive maintenance, surveillance testing, and periodic testing work order tasks that provide opportunities for the visual Inspection of internal surfaces of piping, such as the piping identified in LRA Table 3.4.2-4. Periodic internal inspections of components allow timely detection of degradation and determination of appropriate corrective actions. This program's work activities will monitor parameters that may be detected by visual examination such as loss of material due to pitting and crevice corrosion, by inspecting for discontinuities and imperfections on the surface of the component. The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended function.*

*Based on the above, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to manage loss of material due to pitting and crevice corrosion for stainless steel components in the OTSG Chemical Cleaning System.*

**RAI 3.5.2.2.1.7-1**

Background

The GALL Report, Table 5, indicates that stress corrosion cracking of stainless steel penetration sleeves can occur in all types of PWR containments. In addition, stress corrosion cracking may cause aging effects, particularly if the stainless steel material is not shielded from the corrosive environment. Stress corrosion cracking of stainless steels is known to occur in air containing atmospheric chlorides. Locations near the coast will have much higher concentration of chloride aerosol particles and have a higher susceptibility for stress corrosion cracking.

Issue

LRA Section 3.5.2.2.1.7 indicates that stress corrosion cracking is not applicable for penetration sleeves and dissimilar metal welds because these materials are in the air-indoor environment and not subject to an aggressive chemical environment. It is not clear to the staff how the air-indoor environment is controlled in order to eliminate the chloride aerosols that are prevalent on the coast lines.

Request

Provide additional information on why atmospheric chloride induced stress corrosion cracking does not need to be evaluated for penetration sleeves and dissimilar metal welds in an indoor air environment and why no aging management program has been assigned to these components.

***Response***

*As discussed in the response to RAI 3.3.2.2-1, the CR-3 AMR process utilized deterministic methods based on the EPRI Tools, reviews of plant OE, and consideration of NUREG-1801 guidance to identify applicable aging effects for structures, systems or components (SSCs) subject to aging management. This multi-faceted approach concluded that cracking of stainless steel due to SCC was a potential aging effect in outdoor environments exposed to salt air, but was not identified as applicable to indoor environments.*

**RAI 3.5.2.3-1**

Background

LRA Table 3.5.2-6 contains items addressing melamine (Willtec) foam exposed to indoor air. The applicant proposes that neither the component nor the material and environment combination is evaluated in the GALL Report (Note J). The applicant further proposes that this combination of environment and material is not subject to aging and that no aging management program is required.

Issue

In its review of these items, the staff noted that, at least one manufacturer of melamine foam acoustic insulation panels list the life expectancy of these panels as 12 – 14 years under normal conditions and 7 – 11 years under high humidity conditions.

Request

Based on the advertised life expectancy of melamine foam, please justify the position that this material is not subject to aging in indoor air.

***Response***

*The ceiling panels used at CR-3 are SONEXone panels made of a material called open-cell Willtec acoustical foam. A search for aging effects for the open-cell Willtec material in vendor* *literature for the SONEXone panels did not reveal any aging effects for the material. Technical Support at SONEX stated the ceiling panels, made of open-cell Willtec acoustical foam, have no ill effects due to aging and that only some slight growing/shrinkage due to changes in humidity should be observed. However, the location of the ceiling panels at CR-3 is in the humidity controlled control room. The ceiling panels were installed in 1997 and no aging effects have been detected to date in the CR-3 control room environment. Based on this, CR-3 has reasonable assurance there are no aging effects associated with the open-cell Willtec acoustical foam ceiling panels.*

**RAI B.2.9-6**

Background

LRA Section B.2.9 states that the steam generators at CR-3 are scheduled to be replaced in 2009. However, the staff noted that the applicant did not provide any information in the LRA regarding the design of the new steam generators that will be installed this year.

Issue

The staff cannot determine if the current AMR and AMP addressed by the applicant in sections of LRA Table 3.1.2-1 related to the. present steam generators will still be relevant for the replacement ones. Based on the information provided, the staff needs further information in order to evaluate the sufficiency of the aging management review proposed and the associated aging management programs that could evolve because of the installation of the new steam generators.

Request

1. Specify all differences between the original steam generators and the replacement ones, especially concerning their design and the materials used.

2. For any differences identifed, provide the revised items of LRA Table 3.1.2-1 related to the steam generator and affected by those modifications.

***Response***

1. *The two new Replacement Once Through Steam Generators (ROTSG) are "Equivalent Replacements" for the existing steam generators in terms of physical geometry and performance. Changes have been incorporated in the design to address operational, maintenance and reliability issues of the original OTSGs. Improvements in materials and performance have been addressed including erosion-corrosion resistant 2¼ Cr - 1 Mo material used for all header components.*

   *The following table illustrates how the evaluation material used in the LRA (i.e., carbon steel, low alloy steel, low alloy steel with nickel base alloy cladding, low alloy steel with stainless steel cladding, nickel base alloys, and stainless steel) would be impacted.*

   *The ROTSGs do not have a primary drain connection, but have added five thermocouple connections and two drain/nitrogen injection connections.*

| *Component* | *Original OTSG Material* | *Replacement OTSG Material* | *Material Difference?* |
|---|---|---|---|
| *A. Pressure Boundary* | | | |
| *Primary Heads* | *SA-533-GR. B-CL. 1* | *SA-508 Gr. 3 Cl. 2* | *No* |
| *Secondary Shell* | *SA-212-B* | *SA-508 Gr. 3 Cl. 2* | *No* |
| *Tubesheets* | *A-508-64 CL. 2* | *SA-508 Gr. 3 Cl. 2* | *No* |
| *Steam Outlet Nozzle* | *A-508-64 CL.1* | *SA-508 Gr. 3 Cl. 2* | *No* |
| *Primary Coolant Nozzles (Inlet/Outlet)* | *A-508-64 CL. 1 (Stainless Steel Type 304 Cladding)* | *SA-508 Gr.3 Cl. 2 (Cladding: 308L/309L Stainless, SFA 5.4 E308L/E309L, SFA 5.9 E308L/E309L)* | *No* |
| *Main and Auxiliary Feedwater Inlet Headers* | *SA-106 GR B* | *SA-335 Gr.P22 (FW Pipe) SA-234 Gr. WP22 (FW Fittings) SA-182 F22 CL. 3 (Branch Stub)* | *Yes* |
| *Main and Auxiliary Feedwater Risers and Nozzles* | *SA-105 GR 2* | *SA-335 Gr.P22 (FW Pipe) SA-234 Gr. WP22 (FW Fittings) SA-182 F22 CL. 3 (Branch Stub)* | *Yes* |
| *Primary Head Cladding* | *Stainless Steel Type 304* | *308L/309L Stainless Steel SFA 5.4 E308L/E309L SFA 5.9 E308L/E309L* | *No* |
| *Tubesheet Primary Side Cladding* | *I-82* | *I-52* | *No* |
| *Tubes* | *SB-163 Inconel Alloy 600* | *SB-163 UNS N06690* | *No* |
| *Primary/Secondary Manway Covers* | *SA-516 GR 70* | *SA-533 Type B Cl. 1* | *No* |
| *Handhole/ Inspection Covers* | *SA-516 GR. 70* | *SA-533 Type B Cl. 1* | *No* |
| *B. Steam Generator Internals* | | | |
| *Tube Support Plates* | *SA-212-B* | *SA-516 GR. 70* | *No* |
| *Tie Rods* | *SA-306 GR 70* | *SA-479 Type-410 Cond. 3* | *Yes* |
| *Shrouds* | *SA-515 GR 70* | *SA-516 GR 70* | *No* |
| *C. Others* | | | |
| *Support Pedestal* | *SA-302-B* | *SA-508 Gr. 3 Cl. 2* | *No* |

2. *In Table 2.3.1-1, the Component/Commodity "Steam Generator; Primary Side Drain Nozzles" will be deleted. In addition, the ROTSGs do not have the "Steam Generator; Main Feedwater Nozzle Inlet Header Support Plates and Gussets" and this commodity is also deleted. The commodity "Steam Generator; Transition Ring and Support Skirt" Items have been renamed "Steam Generator; Base Support" to reflect the change in design. In Table 3.1.2-1, the AMR lines associated with the "Steam Generator; Primary Side Drain Nozzles" and "Steam Generator; Main Feedwater Nozzle Inlet Header Support Plates and Gussets" will be deleted. No additional AMR lines are required for the thermocouple connections and the drain/nitrogen injection connections as they would be subsumed under the existing "Steam Generator; Secondary Side Nozzles (Vent, Drain, and Instrumentation)" component/commodity. Plant-specific notes have been added to Table 3.1.2-1 to indicate upgraded material. Revised AMR lines are required to address the material differences for the Steam Generator; Main Feedwater Spray Nozzle Flanges, Steam Generator; Auxiliary Feedwater Nozzle Flanges, Steam Generator; Auxiliary Feedwater Nozzle Inlet Headers, Steam Generator; Main Feedwater Nozzle Inlet Headers, and Steam Generator; Primary Manway and Inspection Opening Covers and Backing Plates.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

**RAI B.2.23-1**

Background

The LRA Section (AMP) B.2.23, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," commits to consistency with the GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," with no exceptions or enhancements. GALL Report AMP XI.M.38 is applicable to steel (carbon steel) components to detect loss of material with the use of visual inspections.

Issue

The applicant's LRA program basis documents and AMR line items stated that the LRA AMP B2.23 is relied upon to manage materials beyond the scope of the GALL Report AMP XI.M38, including stainless steel, aluminum and aluminum alloys, copper and copper alloys, titanium, elastomers, PVC, and thermoplastics in a variety of environments. The CR-3 LRA had also expanded the scope of aging effects managed by this AMP to include cracking due to stress corrosion cracking in metals and hardening and loss of strength in elastomers, PVC, and thermoplastics. The proposed expansion of AMP B2.23 is beyond the scope of GALL AMP XI.M38, which was meant for steel components and loss of material. The LRA states that the program includes a limited scope of preventive maintenance activities that involve physical manipulation or other investigative methods to detect aging effects. The staff is not convinced that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program using visual inspection and limited scope preventive maintenance provides adequate aging management for detecting tight stress corrosion cracks in metals and hardening and loss of strength in elastomers, PVC and thermoplastics.

Request

1. Provide justification for not considering the expansion in the scope of material to include additional metallic, elastomer, PVC, and thermoplastic components and in the scope of aging effects to include cracking due to stress corrosion cracking and hardening and loss of strength to be exceptions to GALL AMP XI.M38.

2. Provide justification that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate for managing the aging effect of cracking due to stress corrosion cracking in the identified carbon steel, stainless steel, aluminum, aluminum alloys, copper, copper alloys, and titanium components, and the aging effects of hardening and loss of strength in elastomers, PVC and thermoplastics.

3. Identify and justify the inspection techniques, including physical manipulation/testing, used by this program that will be capable of detecting stress corrosion cracking and changes in properties for the materials (and the components) added to the scope of this program or provide an appropriate program to manage cracking due to stress corrosion cracking in metals and hardening and loss of strength in elastomers, PVC and thermoplastics for these components.

***Response***

1. *CR-3 has revised the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to consider metals (other than carbon steel), and non-metallic components such as elastomers, fiberglass, PVC, and thermoplastic components as an exception to the scope of GALL AMP XI.M38. Also, the LRA will be revised to consider parameters monitored, and aging effects such as cracking due to stress corrosion cracking, and hardening and loss of strength as exceptions to GALL AMP XI.M38. This program will utilize visual examinations to detect discontinuities and imperfections on the surface of the component, as well as non-visual examinations that may include tactile techniques and physical manipulation. The tactile techniques may include scratching, bending, folding, stretching, and pressing of non-metallics, as detailed below, in conjunction with the visual examinations. These exceptions are considered an augmentation of the NUREG-1801 program. Therefore, a License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

2. *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will include measures to verify that unacceptable degradation of managed components is not occurring. The program will monitor parameters directly related to the degradation of components. Inspections will be performed by qualified personnel following CR-3 procedures and processes. Inspections will be performed periodically such that aging effects will be detected prior to the loss of intended functions. Inspection attributes and acceptance criteria will be provided in the governing procedures, and unacceptable conditions will be resolved through the CR-3 Corrective Action Program, including ongoing monitoring/trending, as appropriate.*

   *Examination techniques will be appropriate to detect and assess the aging mechanisms of concern and will include visual examination and non-visual examination such as ultrasonic testing (UT) or radiography (RT), physical manipulation of elastomers, and investigative methods to determine that hardening and loss of strength is not occurring in non-metallic components.*

3 *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will utilize the NUREG-1801, Volume 2, Section XI.M32 table titled, "Examples of Parameters Monitored or Inspected And Aging Effect for Specific Structure or Component," as guidance in prescribing inspection activities for SSCs in the program. As an example, enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) would be an acceptable means to detect stress corrosion cracking in stainless steel, copper and copper alloys, nickel base alloys, titanium, and aluminum or aluminum alloys. These inspection techniques will be performed by qualified personnel in accordance with CR-3 procedures and processes. Program examination procedures will also include inspection attributes relevant to corrosion of metals, such as visual detection of loss of material, and evidence of corrosion mechanisms, such as rust, oxidation, and discoloration.*

   *Visual examinations to detect age-related degradation of polymers and elastomers would include inspection attributes relevant to degradation of polymers and elastomers, such as cracking, peeling, blistering, chalking, crazing, delamination, flaking, discoloration, physical distortion, gross softening, indications of wear, and loss of material. Tactile techniques for polymers and elastomers would be utilized and could include scratching the material surface to screen for residues that may indicate a breakdown of the polymer material, bending or* *folding of the component which may indicate surface cracking, stretching to evaluate resistance of the polymer material, and pressing on the material to evaluate the resiliency.*

*In addition to visual inspections, elastomeric component examinations will include physical manipulation to detect aging effects, as recommended in EPRI Technical Report 1008035, "Expansion Joint Maintenance Guide," and will be capable of detecting hardening and loss of strength.*

*Acceptance criteria will be developed for the visual and non-visual examinations and be defined in site procedures. For example, physical manipulation of elastomers could include the attributes of no indication of unacceptable hardening, no delamination, or no unacceptable cracking. For thickness measurements of metals, the remaining wall thickness must be sufficient to provide reasonable assurance that the component will continue to perform its component intended function.*

*Based on the above, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate for managing the aging effect of cracking due to stress corrosion cracking in metallic components, and the aging effects of hardening and loss of strength in non-metallic components such as elastomers, fiberglass, PVC, and thermoplastics.*

**RAI B.2.25-1.1**

Progress Energy letter 3F1009-07, dated October 13, 2009, submitted responses to RAIs related to different AMPs. The response to RAI B.2.25-1 stated that the degraded area at the liner to moisture barrier interface that was UT examined in 1997 was not designated as a Surface Area Requiring Augmented Examination in accordance with ASME Subsection IWE-1241. There have been no additional inspections of the degraded area since 1997. One area had a measured pit depth of 0.065 in. with a remaining wall thickness of 0.307 in. at an area of the liner with a UT thickness reading of 0.372 in.

In order to complete its review, the staff requests the following additional information:

1. Explain why the degraded area of the liner plate was not designated for augmented inspection even after the IWE program was implemented at CR-3 in 1997 since the pit due to corrosion at the subject area was 0.065 inch or 17.5 percent of the liner plate thickness. ASME Subsection IWE requires augmented inspection if the base metal thickness is reduced by greater than 10 percent.

2. Plans for inspecting the subject area during the current and future refueling outage.

The above information is required to confirm that the effects of aging of the containment liner plate will be adequately managed so that that it's intended function will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

***Response***

1. *As stated in Progress Energy Letter 3F1009-07, dated October 13, 2009, at the time of discovery in 1997, CR-3 had not yet developed an ASME Section XI IWE/IWL Inspection Program. An engineering evaluation was performed which determined the small cross sectional area of the pit would not significantly affect the overall stress in the liner plate. Following the development and implementation of the IWE/IWL Program in 1999, the area in question was not noted during the IWE examinations performed as it is located below the moisture barrier and is not accessible or visible. Since this area was not identified during the IWE examinations, it was not identified as an augmented inspection area for future examinations.*

2. *During the 2009 refueling outage (R16), the moisture barrier in the area of question was removed and the degraded area of 1997 located. The metal surface area was then cleaned to bare metal. The pit was measured to be approximately 3/32 inch (0.093 inch) deep. A Nuclear Condition Report was initiated to evaluate the condition, and a work order generated to weld-repair the liner plate pit back to nominal wall thickness. Following the repair, a work order will be used to manage re-coating the area and re-applying the moisture barrier seal. This area will be considered an Augmented Inspection area in accordance with IWE-3511 and will be inspected in accordance with the schedule and requirements of IWE-2420(b) and Table IWE-2500-1, Examination Category E-C requirements.*

**RAI B.2.25-2.1**

The response to RAI B.2.25-2 (in the aforementioned October 13, 2009 letter) stated that CR-3 has planned for a full visual examination of the accessible ASME Subsection IWE components including the accessible liner wall and moisture barrier in the 2009 refueling outage (RF016). In addition, CR-3 will be performing repairs of the degraded moisture barrier as needed to ensure a watertight seal between the concrete and the liner plate. Any areas of corrosion of the liner plate which are unsatisfactory will be further evaluated as to the extent of the degradation and any additional corrective actions to be performed. There are no plans to remove the moisture barrier to investigate the condition of the liner plate at the interface point of the liner and the moisture barrier or to remove concrete to inspect the floor liner plate during the 2009 refueling outage.

Explain why CR-3 has no plans to remove the moisture barrier to investigate the condition of the liner plate corrosion at the moisture barrier and wall and floor liner plate below moisture barrier since moisture barrier degradations have been documented starting in 2003 even after the moisture barrier was reinstalled in 1997. In 2007, the moisture barrier was found to be damaged at 12 locations around the circumference. The damaged moisture barrier provides a path for water penetration and corrodes the liner plate. In addition, in 1997, the liner plate was found to be degraded at a number of locations. There has not been any follow up examination of the liner plate even though the moisture barrier has been damaged since 2003.

The above information is required to confirm that the effects of aging of the containment liner plate will be adequately managed so that that it's intended function will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a).(3).

***Response***

*During the IWE visual examination of the moisture barrier in the 2009 refueling outage (R16), all areas of the moisture barrier with indications and areas previously identified with degradation since 2003 were removed. The liner plate at each of these areas was inspected. The only location which was determined to have degradation of the liner at the moisture barrier was the area first seen in 1997 and discussed in the response to RAI B.2.25-1.1. The exposed liner plate will be cleaned and recoated and new moisture barrier installed to ensure a watertight seal at each of the inspected locations.*

*For future IWE examinations, the work orders generated to perform IWE examinations will contain a task to remove the moisture barrier and examine the liner surface for any signs of excessive corrosion and wastage in areas of moisture barrier degradation. This will ensure the effects of aging of the moisture barrier and containment liner plate will be adequately managed during the period of extended operation.*

**RAI B.2.25-3.1**

In Progress Energy Letter 3F1009-07, dated October 13, 2009, the applicant submitted response to RAIs related to different AMPs. In response to RAI B.2.25-3, the applicant stated that there has been no testing to determine the gaps between the liner plate and concrete. Bulges or indications of bulges determined through tapping are identified on inspection data sheets. During the refueling outage in 2007, 28 bulges in the liner plate at various locations were identified during the general visual examination. Two of the bulged areas were 12 in. x 36 in., one was 12 in. x 24 in. and the remainders were all 12 in. x 12 in. It was determined that the areas were minor in nature and did not adversely affect the structural integrity of the Reactor Building or its capability to perform its intended function over the next refueling cycle. These areas will continue to be visually inspected in accordance with ASME Section XI, Subsection IWE requirements.

In order to complete its review, the staff requests the details/basis of the engineering evaluation/analysis which determined that the bulged areas do not adversely affect the ability of the Reactor Building to perform its intended function during the period of extended operation.

The staff needs the above information to confirm that the effects of aging of the containment liner plate will be adequately managed so that it's intended function will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

***Response***

*During the 2009 refueling outage (R16), an ASME Section XI, Subsection IWE program examination was performed on the accessible RB liner plate. In addition to bulges of the liner plate previously identified in 2007, additional bulges were identified during the fall 2009 IWE examination. Per ASME Section XI, IWE-3122, acceptance of components for continued service shall be in accordance with IWE-3122 by Examination, Corrective Measures or Repair/Replacement Activity, or by Engineering Evaluation. A Nuclear Condition Report has been initiated and will be evaluated by Engineering prior to acceptance of the liner plate with the identified liner plate areas which are bulged.*

*The details and basis of this engineering evaluation or analysis will be available for NRC review prior to return to operation of CR-3 from the fall 2009 refueling outage.*

**RAI B.2.26-1.1**

The response to RAI B.2.26-1 (provided by letter dated October 13, 2009) stated that the original wire relaxation curve, provided by test data from the wire vendor, forms the bases for the wire relaxation value. The original wire relaxation curve was based on the wire described in the FSAR Section 5.2.2.3 and the relaxation curve shown on FSAR Figure 5-26. The values on FSAR Figure 5-26 for wire number 6 were multiplied by a factor of 2.68 to obtain the relaxation loss in percent at specific years. The 2.68 multiplication factor was from two factors. A 1.47 factor was determined to allow for a long term temperature of 104°F vs. 68°F on FSAR Figure 5-26. A 1.82 factor was determined based on a conservative relaxation value of 2% at 40 years, as opposed to a 1.1% on FSAR Figure 5-26 (2.0/1.1).

Explain in detail the basis for the 1.47 factor that was used for relaxation of prestressing steel due to a long term temperature of 104°F vs. 68°F or alternately any test data to support this assumption.

The above information is required to confirm that the effects of aging of the containment liner plate will be adequately managed so that that it's intended function will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

***Response***

*The 1.47 factor, which was used for relaxation of prestressing steel due to a long term temperature of 104°F versus 68°F, was developed based on using the wire relaxation curve in FSAR Figure 5-26 (for wire number 6) that is based on 20°C (68°F) and comparing to a 40°C (104°F) curve. A documented discussion with the Prescon Corporation, the post-tensioning system supplier, stated the curves are parallel. In addition, at 1,000 hours, the 68°F curve indicates a 0.75% relaxation, while the 104°F curve indicates about 1.1% relaxation. Based on this, a ratio of 1.47 was determined by dividing 1.1% by 0.75%. A CR-3 design calculation documents this methodology.*

**RAI B.2.31-1.1**

Background

GALL AMP XI.E1, under Element 4 (Detection of Aging Effects) states that a representative sample of accessible electrical cables and connection installed in adverse localized environment should be visually inspected for cable and connections jacket surface anomalies. LRA AMP B.2.31 stated that it will utilize plant operating experience to determine the areas to be inspected. It further stated that based on this review of operating experience (OE), the plant areas to be inspected become localized in nature, consisting of limited area of a much larger plant areas or zone. In a letter dated September 11, 2009 (RAI B2.31-1), the staff requested technical justification how Element 4 of AMP B.2.31 is consistent with that in GALL AMP XI.E1 and how it will envelop electrical cables and connections in the scope of this aging management program located in adverse localized environments.

The response to the staff request, in a letter dated October 13, 2009, stated that the CR-3 AMP utilizes OE to establish where adverse localized environment may exist and determine the plant area to be inspected. OE covers a wide range of plant-specific documents and industry related guidance. The RAI response also stated that site specific OE includes the use of EQ zone maps, environmental survey, maintenance record, corrective actions and conversations with plant personnel to establish where the adverse localized environments may exist based on past cable failures, cables that exhibited the effects of aging, areas of localized overheating, hot spots, etc.

Issue

The staff questioned the basis for determining adverse localized environments. Solely relying on OE alone may not identify/envelop all adverse localized environments. The adverse localized environment could be those created by elevated temperature such as steam generators, feedwater heaters, main steam valves, uninsulated or unshielded hot process piping, steam or packing leaks, high-powered incandescent lighting, motor exhaust air vents, areas with equipment that operate at high temperature, areas with inadequate ventilation, etc., are sources of adverse localized environments. Electrical cables and connections normally within three feet of these sources may be subjected to an adverse localized environment. Adverse localized environment can be identified through plant OE reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys.

Request

Provide additional technical justification of how utilizing OE alone will identify/envelop all adverse localized environments, or clarify how items such as communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys are or will be used to identify adverse localized environment.

***Response***

*Operating Experience is a tool, but not the only tool, utilized by CR-3 to identify adverse localized environments associated with cable and connection inspections for GALL AMP XI.E1. In preparing for GALL AMP XI.E1 cable and connection inspections, plant personnel identify adverse localized environments through an integrated approach. This methodology includes the review of Environmental Qualification (EQ) zone maps that show radiation levels and temperatures for various plant areas, consultations with plant staff who are cognizant of plant conditions, utilization of infrared thermography to identify hot spots on a real time basis, and the review of relevant plant specific and industry OE. Through the use of these tools, adverse localized environments are identified and an inspection plan developed that assures cables and connections in these areas are inspected for aging degradation.*

**_Supplemental Response to RAI 2.3-04 Regarding Jacket Cooling System_**

*The NRC staff requested clarification of the response to RAI 2.3-04 regarding scoping of diesel generator turbo-chargers provided in CR-3 letter to the NRC, 3F1109-05, "Crystal River Unit 3 - Response to Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant, License Renewal Application (TAC NO. ME0274) - Section 2.3," dated November 12, 2009.*

*RAI 2.3-04, item 2.3.3.29, questioned the AMR basis of the Emergency Diesel Generator turbo-charger. The response to this RAI stated that the turbo-charger had been screened as a complex assembly. Upon further consideration, CR-3 has revised this position to consider the turbo-charger casing to be a passive part of the emergency diesel generator exhaust system piping. The carbon steel diesel exhaust piping and silencer are identified in Table 3.3.2-33 in the Diesel Exhaust Silencers line item. The turbo-charger casing is considered to be part of the exhaust piping and is included in this line. However, the turbo-charger internals, including subcomponents associated with cooling water and lubrication, are considered to be tested and verified as part of the complex assembly and, therefore, not subject to AMR.*

**_Supplemental Response to RAI 2.4-1_**

*During a telephone conversation with the NRC, Progress Energy agreed to provide additional clarification to RAI 2.4-1 concerning the use of fire barrier assemblies and reinforced concrete structural fire barriers (walls, ceilings, and floors). The original response to RAI 2.4-1 is contained in CR-3 letter to NRC, 3F0909-06, "Crystal River Unit 3 - Response to Requests for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant, License Renewal Application (TAC NO. ME0274) and Amendment #4," dated September 30, 2009.*

*A description of the commodity group "Fire Barrier Assemblies" and the structures in which they are located is provided in RAI Response 2.3.3.36-3 in the abovementioned CR-3 letter to NRC, 3F0909-06.*

*Reinforced concrete structural fire barriers (walls, ceilings and floors) are included with the "Concrete: Above Grade" commodity group for the Auxiliary Building, Control Complex, Diesel Generator Building, Emergency Feedwater Pump Building, Intermediate Building, and Turbine Building. "Concrete: Above Grade" is identified with a C-4 (Fire Barrier) intended function in respective LRA Scoping and Screening Tables 2.4.2-1, 2.4.2-5, 2.4.2-9, 2.4.2-10, 2.4.2-13, 2.4.2-18 and LRA AMR Tables 3.5.2-2, 3.5.2-6, 3.5.2-10, 3.5.2-11, 3.5.2-14, and 3.5.2-19. These structures are inspected on a frequency not exceeding 10 years by the Structures Monitoring Program implementing document as discussed in response to RAI B.2.30-1 in CR-3 to NRC letter, 3F1009-07, "Crystal River Unit 3 - Response to Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant License Renewal Application (TAC NO. ME0274) and Amendment #5."*

*In addition, for the RB, reinforced concrete structural fire barriers are included with the commodity group "Concrete: Dome; Wall; Basemat; Ring Girder; Buttresses." However, only the cylinder wall of the RB is considered a reinforced concrete structural fire barrier between the adjoining Auxiliary and Intermediate Buildings. None of the walls, ceilings and floors inside the RB are credited with a fire barrier function in the Fire Protection Program. The commodity group "Concrete: Dome; Wall; Basemat; Ring Girder; Buttresses" is identified with a C-4 (Fire*

*Barrier) intended function in LRA Scoping and Screening Table 2.4.1-1 and LRA AMR Table 3.5.2-1. The RB reinforced concrete, including the cylinder wall, is inspected on five-year intervals by the ASME Section XI, Subsection IWL Program.*

***Supplemental Response to RAI B.2.30-4***

*The following information supplements the information submitted in response to RAI B.2.30-4 in CR-3 to NRC letter, 3F1009-07: "Crystal River Unit 3 - Response to Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant License Renewal Application (TAC NO. ME0274) and Amendment #5."*

*Based on a follow-up conversations with CR-3, the NRC staff expressed concern with the high chloride content (1300 ppm ) of the stalactite sample collected in the Tendon Access Gallery. This could indicate the rebar and other embedments in the concrete are in a high chloride environment which could lead to corrosion of rebar and embedments.*

*Based on this, CR-3 agreed to provide additional information to validate that concrete exposed to groundwater is adequately providing a passive environment which will protect the rebar and embedment from degradation during the period of extended operation. To this end, CR-3 will add a civil/structural item to the One-Time inspection Program in LRA Subsection B.2.18. The One-Time inspection to be performed, prior to the extended period of operation will involve taking core samples of concrete from the Tendon Access Gallery concrete wall where leaching has been observed. The core sample will be taken from the inside face of the concrete up to the rebar. The concrete cores will be tested to determine if the water soluble chlorides that could lead to corrosion of the embedded steel and reinforcing steel are present. In addition, the exposed rebar will be examined to determine its condition and if it has any significant corrosion which could affect the ability of the concrete to perform its intended function.*

*The One-Time Inspection Program uses one-time inspections to verify the effectiveness of an aging management program and confirm the absence of aging effects. Therefore, the One-Time Inspection Program is appropriate for confirming the presence or absence of this potential aging mechanism.*

*A License Renewal Application (LRA) amendment is required; refer to Enclosure 2.*

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ENCLOSURE 2

AMENDMENT #8, CHANGES TO THE LICENSE RENEWAL APPLICATION

**Amendment #8, Changes to the License Renewal Application**

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>RAI 3.1.2.1-4</td><td>Add the following AMR line for Steam Generator; Tubesheets on LRA Page 3.1-124:
<table>
<tr><td rowspan="2">Low Alloy Steel</td><td rowspan="2">Treated Water (Inside)</td><td>Cumulative Fatigue Damage due to Fatigue</td><td>TLAA</td><td>IV.D2-3 (R-222)</td><td>3.1.1-10</td><td>A</td></tr>
<tr><td>Loss of Material due to Crevice Corrosion<br>Loss of Material due to General Corrosion<br>Loss of Material due to Pitting Corrosion</td><td>Water Chemistry and One-Time Inspection</td><td>IV.D2-8 (R-224)</td><td>3.1.1-12</td><td>A</td></tr>
</table>
</td></tr>
<tr><td>RAI 3.1.2.1-6</td><td>On LRA Page 3.1-134, revise the AMR lines for the Steam Generator; Tubes with the M-5 function as follows:
<table>
<tr><td rowspan="2">Nickel Base Alloys</td><td>Reactor Coolant (Inside)</td><td>Reduction of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces</td><td>Water Chemistry</td><td></td><td></td><td>J, 104, 109</td></tr>
<tr><td>Treated Water (Outside)</td><td>Reduction of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces</td><td>Water Chemistry</td><td></td><td></td><td>J, 104, 109</td></tr>
</table>
</td></tr>
<tr><td>RAI 3.2.2.1-1</td><td>Add the following AMR lines to the indicated LRA components/commodities:

- RCPB Piping; Reactor Coolant Pump Safe Ends on LRA Page 3.1-92, and
- RCPB Piping; Hot Leg Surge Line Nozzle Safe End on LRA Page 3.1-97:

<table>
<tr><td>Stainless Steel</td><td>Reactor Coolant (Inside)</td><td>Cracking due to Cyclic Loading</td><td>ASME Section XI Inservice Inspection</td><td>IV.C2-26 (R-58)</td><td>3.1.1-62</td><td>A</td></tr>
</table>

- RCPB Piping; Flow Meter Assembly on LRA Page 3.1-94, and
- RCPB Piping; Hot Leg Surge Line Nozzle on LRA Page 3.1-97:

<table>
<tr><td>Carbon Steel with Stainless Steel Cladding</td><td>Reactor Coolant (Inside)</td><td>Cracking due to Cyclic Loading</td><td>ASME Section XI Inservice Inspection</td><td>IV.C2-26 (R-58)</td><td>3.1.1-62</td><td>A</td></tr>
</table>

- RCPB Piping; Class 1 Valve Bodies on LRA Page 3.1-109:

<table>
<tr><td>Cast Austenitic Stainless Steel</td><td>Reactor Coolant (Inside)</td><td>Cracking due to Cyclic Loading</td><td>ASME Section XI Inservice Inspection</td><td>IV.C2-26 (R-58)</td><td>3.1.1-62</td><td>A</td></tr>
</table>

(continued)</td></tr>
</table>

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>RAI 3.2.2.1-1 (continued)</td><td>
<ul>
<li>Pressurizer; Surge Line Nozzle Thermal Sleeve on LRA Page 3.1-116,</li>
<li>Pressurizer; Spray Line Nozzle Thermal Sleeve on LRA Page 3.1-117,</li>
<li>Pressurizer; Surge Line Nozzle Safe End on LRA Page 3.1-119,</li>
<li>Pressurizer; Manway Covers/Insert on LRA Page 3.1-121,</li>
<li>Pressurizer; Heater Bundle Diaphragm Plate on LRA Page 3.1-122,</li>
<li>Pressurizer; Immersion Heater Sheath on LRA Page 3.1-122, and</li>
<li>Pressurizer; Immersion Heater End Plug on LRA Page 3.1-123:</li>
</ul>
<table>
<tr><td>Stainless Steel</td><td>Reactor Coolant (Inside)</td><td>Cracking due to Cyclic Loading</td><td>ASME Section XI Inservice Inspection and Water Chemistry</td><td>IV.C2-18 (R-58)</td><td>3.1.1-67</td><td>A</td></tr>
</table>
<ul>
<li>Pressurizer; Manway on LRA Page 3.1-120:</li>
</ul>
<table>
<tr><td>Low Alloy Steel with Stainless Steel Cladding</td><td>Reactor Coolant (Inside)</td><td>Cracking due to Cyclic Loading</td><td>ASME Section XI Inservice Inspection</td><td>IV.C2-18 (R-58)</td><td>3.1.1-67</td><td>A</td></tr>
</table>
</td></tr>
<tr><td>RAI 3.2.2.2-1</td><td>On LRA Page 3.2-28, revise the AMR line for the Core Flood Tanks, nickel base alloy material as follows:
<table>
<tr><td>Nickel Base Alloys</td><td>Treated Water (Inside)</td><td>Cracking due to SCC</td><td>ASME Section XI Inservice Inspection, Water Chemistry, and Nickel-Alloy Commitment</td><td>IV.C2-21 (R-06)</td><td>3.1.1-31</td><td>C, 205</td></tr>
</table>
</td></tr>
<tr><td>RAI 3.2.2.3-1</td><td>On LRA Page 3.4-69, for the EFW System commodity Piping Insulation, delete the AMR line item for Air-Outdoor (Outside) environment.</td></tr>
<tr><td>RAI 3.3.2.21-1</td><td>On LRA Page 3.3-188, for the PASS Sample Cooler Tubes subject to Treated Water (Inside), revise the AMP to be a combination of the Water Chemistry and One-Time Inspection Programs for managing the aging effect of Reduction of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces.</td></tr>
<tr><td>Progress Energy-Identified Change</td><td>Add the following AMR line for Raw Water (Inside) to the PASS Sample Cooler Tubes on LRA Page 3.3-188:
<table>
<tr><td>Raw Water (Inside)</td><td>Reduction of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces</td><td>Inspection of Internal Surfaces in Miscel-laneous Piping and Ducting Components</td><td></td><td></td><td>J</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>Progress Energy-Identified Change</td><td>Add the following AMR line for Raw Water (Inside) to the Stainless Steel Containment Isolation Piping and Components on LRA Page 3.3-186 and to the Stainless Steel Piping, piping components, piping elements, and tanks, on Page 3.3-190:
<table>
<tr><td>Raw Water (Inside)</td><td>Cracking due to SCC<br>Loss of Material due to Crevice Corrosion<br>Loss of Material due to Microbiologically Influenced Corrosion (MIC)<br>Loss of Material due to Pitting Corrosion</td><td>Inspection of Internal Surfaces in Miscel-laneous Piping and Ducting Components</td><td></td><td></td><td>J</td></tr>
</table></td></tr>
<tr><td>Progress Energy-Identified Change</td><td>Add the following AMR line for Raw Water (Inside) to the PASS Sample Cooler Components fabricated of Nickel Base Alloys on LRA Page 3.3-187:
<table>
<tr><td>Raw Water (Inside)</td><td>Cracking due to SCC<br>Loss of Material due to Crevice Corrosion<br>Loss of Material due to Microbiologically Influenced Corrosion (MIC)<br>Loss of Material due to Pitting Corrosion</td><td>Inspection of Internal Surfaces in Miscel-laneous Piping and Ducting Components</td><td></td><td></td><td>J</td></tr>
</table></td></tr>
<tr><td>RAI 3.3.2.36-1</td><td>Delete the AMR line items associated with the material PVC or Thermoplastics from LRA Table 3.3.2-36 on Page 3.3-289.</td></tr>
<tr><td>RAI 3.3.2.36-3</td><td>Revise the AMPs credited for aging management of Fire Protection System Piping, piping components, standpipes, hydrants, and tanks subjected to a Fuel Oil (Inside) environment on LRA Page on Page 3.3-284 to credit a combination of the Fire Protection, Fuel Oil Chemistry, and One-Time Inspection Programs.</td></tr>
</table>

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>RAI B.2.9-6</td><td>
On LRA Page 2.3-10, delete the line items in Table 2.3.1-1 for the Steam Generator; Main Feedwater Nozzle Inlet Header Support Plates and Gussets and for the Steam Generator; Primary Side Drain Nozzles. Also, on Page 2.3-10, change the line item for Steam Generator; Transition Ring and Support Skirt Items to Steam Generator; Base Support, and revise the component/commodity Steam Generator; Tubes and Sleeves to Steam Generator; Tubes.
On LRA Page 3.1-124, add new plant-specific Note 107 to the existing AMR lines for the Steam Generator; Tubesheets.
On LRA Page 3.1-126, replace the AMR lines for the Steam Generator; Main Feedwater Spray Nozzle Flanges fabricated from carbon steel with the following:
<table>
<tr><td rowspan="4">Stainless Steel</td><td rowspan="3">Treated Water (Inside)</td><td>Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.D1-4 (SP-16)</td><td>3.4.1-16</td><td>A</td></tr>
<tr><td>Cracking due to SCC</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.D1-5 (SP-17)</td><td>3.4.1-14</td><td>A</td></tr>
<tr><td>Cumulative Fatigue Damage due to Fatigue</td><td>TLAA</td><td>V.D1-27 (E-13)</td><td>3.2.1-01</td><td>C</td></tr>
<tr><td>Air - Indoor Uncontrolled (Outside)</td><td>None</td><td>None</td><td>IV.E-2 (RP-04)</td><td>3.1.1-86</td><td>A</td></tr>
</table>
On LRA Page 3.1-127, replace the AMR lines for the Steam Generator; Auxiliary Feedwater Spray Nozzle Flanges fabricated from carbon steel with the following:
<table>
<tr><td rowspan="4">Stainless Steel</td><td rowspan="3">Treated Water (Inside)</td><td>Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.G-32 (SP-16)</td><td>3.4.1-16</td><td>A</td></tr>
<tr><td>Cracking due to SCC</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.G-33 (SP-17)</td><td>3.4.1-14</td><td>A</td></tr>
<tr><td>Cumulative Fatigue Damage due to Fatigue</td><td>TLAA</td><td>V.D1-27 (E-13)</td><td>3.2.1-01</td><td>C</td></tr>
<tr><td>Air - Indoor Uncontrolled (Outside)</td><td>None</td><td>None</td><td>IV.E-2 (RP-04)</td><td>3.1.1-86</td><td>A</td></tr>
</table>
On LRA Page 3.1-128, add new plant-specific Note 108 to the existing AMR lines for the Steam Generator; Auxiliary Feedwater Nozzle Inlet Headers.
On LRA Page 3.1-129, add new plant-specific Note 108 to the existing AMR lines for the Steam Generator; Main Feedwater Nozzle Inlet Headers.
On LRA Page 3.1-129, delete the AMR lines associated with the Steam Generator; Main Feedwater Nozzle Inlet Header Support Plates and Gussets.
(continued)
</td></tr>
</table>

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>RAI B.2.9-6<br>(continued)</td><td>
On LRA Page 3.1-130, delete the AMR lines associated with the Steam Generator; Primary Side Drain Nozzles.
On LRA Page 3.1-132, replace the AMR lines for the Steam Generator; Primary Manway and Inspection Opening Covers and Backing Plates fabricated from stainless steel with the following:
<table>
<tr><td rowspan="3">Nickel Base Alloys</td><td rowspan="3">Reactor Coolant (Inside)</td><td>Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion</td><td>Water Chemistry</td><td>IV.C2-15 (RP-23)</td><td>3.1.1-83</td><td>A</td></tr>
<tr><td>Cracking due to SCC</td><td>ASME Section XI Inservice Inspection and Water Chemistry</td><td>IV.D2-4 (R-35)</td><td>3.1.1-35</td><td>A</td></tr>
<tr><td>Cumulative Fatigue Damage due to Fatigue</td><td>TLAA</td><td>IV.D2-3 (R-222)</td><td>3.1.1-10</td><td>A</td></tr>
</table>
On LRA Page 3.1-133 revise Steam Generator; Transition Ring and Support Skirt Items to Steam Generator; Base Support.
On LRA Pages 3.1-133 and 3.1-134, revise Steam Generator; Tubes and Sleeves to Steam Generator; Tubes and add plant-specific Note 109 to the AMR lines for the Steam Generator; Tubes and Steam Generator; Tube Plugs.
On LRA Page 3.1-135, replace the AMR lines for the Steam Generator; Tube Support Plate Assembly (Support Rods) fabricated from carbon steel with the following:
<table>
<tr><td rowspan="3">Stainless Steel</td><td rowspan="3">Treated Water (Outside)</td><td>Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.D1-4 (SP-16)</td><td>3.4.1-16</td><td>C</td></tr>
<tr><td>Cracking due to SCC</td><td>Water Chemistry and One-Time Inspection</td><td>VIII.D1-5 (SP-17)</td><td>3.4.1-14</td><td>C</td></tr>
<tr><td>Cumulative Fatigue Damage due to Fatigue</td><td>TLAA</td><td>IV.D2-10 (R-33)</td><td></td><td>F</td></tr>
</table>
On LRA Page 3.1-144, add the following three plant-specific notes:
107. The cladding for the Replacement OTSGs is I-52 as opposed to the original OTSGs cladding that is I-82.
108. Erosion-corrosion resistant 2¼ Cr - 1 Mo material used for all header components in place of the original OTSG`s carbon steel components.
109. The material for the replacement OTSGs is Alloy 690 TT.
</td></tr>
<tr><td>RAI B.2.22-1 from CR-3 Letter 3F1009-07, dated October 13, 2009</td><td>In the AMR Tables in LRA Sections 3.1 through 3.4, for each line item that credits the External Surfaces Monitoring Program, change each Generic Note A to Note B and each Generic Note C to Note D. This is to reflect that the AMP consistency with NUREG-1801 has been changed from consistent to consistent with exceptions.</td></tr>
</table>

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #8 Changes</th></tr>
<tr><td>RAI B.2.23-1</td><td>Revise LRA Subsection B.2.23 on page B-75 as follows:<br><br>Change the NUREG-1801 Consistency to read:<br><br>The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program consistent with NUREG-1801, Section XI.M38, with exceptions.<br><br>Add the following under Exceptions to NUREG-1801:<br><br><u>Program Elements Affected</u><br>• Scope of Program<br>The Program addresses aging effects for materials in addition to carbon steel. This is justified because appropriate administrative controls and examination techniques will be applied to components that credit the Program.<br><br>• Parameters Monitored/Inspected<br>The Program is applied to aging effects beyond those identified in NUREG-1801. This is acceptable because selected examination techniques will be appropriate for detecting and assessing the aging effects/mechanisms of concern and will include visual and non-visual methods such as volumetric examinations and physical manipulation.<br><br>• Detection of Aging Effects<br>The Program is applied to aging effects beyond those identified in NUREG-1801. This is acceptable because selected examination techniques will be appropriate for detecting and assessing the aging effects/mechanisms of concern and will include visual and non-visual methods such as volumetric examinations and physical manipulation.<br><br>In the AMR Tables in LRA Sections 3.2 through 3.4, for each line item that credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, change each Generic Note A to Note B and each Generic Note C to Note D.</td></tr>
<tr><td>RAI B.2.30-4 from letter 3F1009-07, dated October 13, 2009 - Supplemental Response</td><td>Add the following row to the table contained in the Program Description of LRA Subsection B.2.18 on Page B-63:<br><br><table><tr><th>Structure/Component</th><th>Building Structure/ System</th><th>Aging Effect of Concern</th></tr><tr><td>Concrete: Above Grade<br>Concrete: Below Grade<br>Concrete: Foundation</td><td>Reactor Building (Tendon Access Gallery)</td><td>Change in Material Properties<br>Loss of Material (Rebar)</td></tr></table></td></tr>
</table>

| Source of Change | License Renewal Application Amendment #8 Changes |
|---|---|
| Progress Energy-Identified Change | In addition to LRA impacts associated with the ROTSGs, CR-3 identified the following changes associated with modifications occurring during the current refueling outage:<br><br>On LRA Page 3.1-94, add plant-specific Note 106 to the existing AMR lines for the RCPB Piping; Flow Meter Assembly.<br><br>On LRA Page 3.1-95, add plant-specific Note 106 to the existing AMR lines for the RCPB Piping; Flow Meter Branch Connections and RCPB Piping; Hot Leg Instrumentation and RTE Connections.<br><br>On LRA Page 3.1-96, add plant-specific Note 106 to the existing AMR lines for the RCPB Piping; Hot Leg High Point Vent Branch Connection.<br><br>On LRA Page 3.1-98, add plant-specific Note 105 to the existing AMR lines for the RCPB Piping; Hot Leg Surge Nozzle Weld. |