December 1, 2009

Mr. Jon Franke, Vice President
Crystal River Nuclear Plant (NA1B)
ATTN: Supervisor, Licensing & Regulatory Programs
15760 W. Power Line Street
Crystal River, Florida 34428-6708

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT, LICENSE RENEWAL APPLICATION (TAC NO. ME0274)

Dear Mr. Franke:

By letter dated December 16, 2008, Florida Power Corporation submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part *54*, to renew the operating license for Crystal River Unit 3 Nuclear Generating Plant (CR-3), for review by the U.S. Nuclear Regulatory Commission (NRC or the staff). The staff is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. Michael Heath, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me at 301-415-3733 or by e-mail robert.kuntz@nrc.gov.

Sincerely,

\RA

Robert F. Kuntz, Sr. Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosure:
As stated

cc w/encl: See next page

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Docket No. 50-302
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As stated
cc w/encl: See next page
DISTRIBUTION: See next page
ADAMS Accession No.: ML093030147

OFFICE	PM:RPB2:DLR	LA:DLR	BC:RPB2:DLR	PM:RPB2:DLR
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DATE	11/16/09	11/27/09	11/30/09	12/1/09

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REQUEST FOR ADDITIONAL INFORMATION

LICENSE RENEWAL APPLICATION FOR

CRYSTAL RIVER UNIT 3

DOCKET NO: 50-302

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.

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.

ENCLOSURE

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.

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.

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.

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.

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.

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).

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.

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 recommends 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.

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.

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.

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.

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.

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.

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?

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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 strenght 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 strenght in elastomers, PVC and thermoplastics for these components.

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).

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).

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 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).

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).

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.

Letter to J. Franke from R. Kuntz, dated December 1, 2009

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SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT, LICENSE RENEWAL APPLICATION (TAC NO. ME0274)

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