July 1, 2002

Mr. J.A. Stall
Senior Vice President
Nuclear and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 1400
Juno Beach, FL 33408-0420

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF SECTIONS 2.0, 3.0, 4.0, AND APPENDIX B OF THE APPLICATION FOR RENEWED OPERATING LICENSES FOR ST. LUCIE UNITS 1 AND 2

Dear Mr. Stall:

By letter dated November 29, 2001, Florida Power and Light Company (FPL) submitted to the U.S. Nuclear Regulatory Commission (NRC) an application, pursuant to Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), to renew the operating licenses for the St. Lucie Nuclear Plant, Units 1 and 2. The NRC staff is reviewing the information contained in this license renewal application (LRA) and has identified, in the enclosure, areas where additional information is needed to complete its review. Specifically, the enclosed request for additional information (RAI) concerns the following sections of the LRA:

- Sec. 2.1: Scoping and Screening Methodology
- Sec. 2.3: System Scoping and Screening Results – Mechanical Systems
- Sec. 2.4: Scoping and Screening Results – Structures
- Sec. 3.2: Aging management Review: Engineered Safety Features
- Sec. 3.4: Aging Management Review: Steam and Power Conversion Systems
- Sec. 3.5: Aging Management Review: Structures and Structural Components
- Sec. 3.6: Aging Management of Electrical and Instrumentation and Controls
- Sec. 4.1: Identification of Time-Limited Aging Analyses
- Sec. 4.3: Metal Fatigue
- Sec. 4.4: Environmental Qualification of Electrical Equipment
- Sec. 4.5: Containment and Penetration Fatigue Analysis
- Sec. 4.6.3 Unit 1 Core Support Barrel Repair
- Sec. B.3.1.3: Pipe Wall Thinning Inspection Program
- Sec. B 3.2.2: ASME Section XI Inservice Inspection Programs
- Sec. B 3.2.8: Fire Protection Program
- Sec. B 3.2.10: Intake Cooling Water System Inspection Program
- Sec. B 3.2.11: Periodic Surveillance and Preventive Maintenance Program

Please provide a schedule, by letter or electronic mail, for submitting your response within 30 days of the receipt of this letter. Additionally, the staff would be willing to meet with FPL prior to the submittal of the response to clarify the staff's request for additional information.

Sincerely,

*/**Original signed by**/*

Noel Dudley, Senior Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos.: 50-335 and 50-389

Enclosure: As stated

cc w/encl: See next page

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REQUEST FOR ADDITIONAL INFORMATION
ST. LUCIE UNITS 1 AND 2

The staff of the U.S. Nuclear Regulatory Commission (NRC) met with representatives of the Florida Power and Light Company (FPL) on May 15-16, 2002, to discuss draft requests for additional information (RAI) concerning the license renewal application for St. Lucie, Units 1 and 2. The staff and FPL also held teleconferencing calls on May 28 and 29, 2002, to continue their discussion of the draft RAIs. On the basis of these discussions, the staff is issuing the following RAIs.

The staff requests that FPL provide a schedule for submitting its response to these RAIs. The staff is willing to meet with FPL prior to submitting the response to clarify its request for additional information.

2.1 SCOPING AND SCREENING METHODOLOGY

RAI 2.1 - 1

By letters dated December 3, 2001, and March 15, 2002, the staff issued interim staff guidance to the Nuclear Energy Institute (NEI). The described areas to be considered and options the staff expects licensees to use to determine what systems, structures, or components (SSCs) meet the criterion defined in Title 10, Section 54.4(a)(2), of the *Code of Federal Regulations* 10 (CFR 54.4(a)(2)) (i.e., all non-safety-related SSCs of which failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i), (ii), or (iii) of that section.)

The staff's letter dated December 3, 2001, provided specific examples of operating experience that identified pipe failure events (summarized in Information Notice 2001-09, Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized-Water Reactor") and the approaches that the staff considers acceptable to determine which piping systems should be included within the scope of license renewal based on the criterion defined in 10 CFR 54.4(a)(2).

The staff's letter dated March 15, 2002, further described the staff's expectations regarding the evaluation of non-piping SSCs to determine which additional non-safety-related SSCs are within the scope of license renewal. The staff position states that applicants should not consider hypothetical failures, but should base their evaluations on each plant's current licensing basis, engineering judgement and analyses, and relevant operating experience. The letter further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation would include the NRC's generic communications and event reports, plant-specific condition reports, industry reports such as significant operating experience reports (SOER's) and engineering evaluations.

Consistent with the staff position described in the aforementioned letters, please describe the scoping methodology that you have implemented for the evaluation of the criterion defined in 10 CFR 54.4(a)(2). As part of your response, please indicate the option(s) credited, list the SSCs included within scope as a result of your efforts, list those structures and components for which aging management reviews were conducted, and describe (as applicable for each structure or component) the aging management programs that will be credited for managing the identified aging effects.

RAI 2.1 - 2

By a letter dated April 1, 2002, the NRC issued a staff position to the NEI, which clarified the use of alternate ac power sources within the context of the Station Blackout (SBO) Rule and described that the offsite power system, which is used to connect the plant to the offsite power source, should be included within the scope of license renewal. The implementation of this staff position will begin with license renewal applications that are currently under review, such as St. Lucie, Units 1 and 2.

Consistent with the staff position described in the aforementioned letter, please describe the process used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3). As part of your response, please list those additional SSCs included within scope as a result of your efforts, list those structures and components for which aging management reviews were conducted, and describe (as applicable for each structure or component) the aging management programs that will be credited for managing the identified aging effects.

RAI 2.1 - 3

During the audit of the St Lucie scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated FSAR Supplement," and Appendix B, "Aging Management Programs." The purpose of this review was to ensure that the applicant's aging management activities are consistent with the staff's guidance described in Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

Based on the staff's evaluation, the description and applicability of the aging management programs and their associated attributes to all safety-related and non-safety-related structures and components provided in Appendix B of the license renewal application (LRA) are consistent with the staff's position regarding quality assurance for aging management. However, the applicant has not sufficiently described the use of the quality assurance program and its associated attributes in the updated Final Safety Analysis Report (UFSAR) supplement discussion provided in Appendix A to the LRA. The staff requests that the applicant revise the description in the updated FSAR supplement, Chapter 18.0, "Aging Management Programs and Time-Limited Aging Analyses Activities," to include aspects of the quality assurance program consistent with the description provided in Appendix B to the LRA.

2.3 SCOPING AND SCREENING RESULTS – MECHANICAL SYSTEMS

2.3.1 Reactor Coolant System

RAI 2.3.1 - 1

The UFSARs for St. Lucie indicate that Units 1 and 2 are required to be in cold shutdown following some postulated fire events. However, the applicant states on page 3.1-11 of the LRA that the pressurizer spray heads do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and, therefore, are not within the scope of license renewal. The staff requests that the applicant explain whether the components, which spray water inside the pressurizer to condense steam (auxiliary spray), are relied upon to take the units to cold shutdown following the postulated fire events. Also consider postulated SBO events that require the Units to be in cold shutdown.

RAI 2.3.1 - 2

The applicant states on page 3.1-11 of the LRA that pressurizer thermal sleeves do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and, therefore, are not within the scope of license renewal. The applicant further states that the thermal sleeves are not part of the pressure boundary, but do provide thermal shielding to the surge and spray nozzles of the pressurizer to minimize fatigue for those nozzles, which might otherwise result from thermal cycles. Fatigue has been identified as an aging effect requiring a time-limited aging analysis (TLAA), and is analytically addressed in section 4.3.1 of the LRA. The staff concludes that since the thermal sleeves were credited in the TLAA for the nozzles (pressure boundary), they should require an aging management program. Operable thermal sleeves are relied upon to allow the nozzles to perform their intended safety functions during the extended period of operation and, therefore, the thermal sleeves should be within the scope of license renewal, pursuant to 10 CFR 54.4(a)(2). Furthermore, the Westinghouse Owners Group has committed in topical report WCAP-14574-A, “License Renewal Evaluation: Aging Management Evaluation for Pressurizers,“ and the staff has concurred that the pressurizer surge nozzle and the spray nozzle thermal sleeves should require an aging management review.

The staff requests that the applicant perform an aging management review of the subject components, or justify why one is not required.

RAI 2.3.1 - 3

In Section 3.1.3 of the LRA, the applicant states that reactor vessel flange leak detection lines do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and, therefore, are not within the scope of license renewal. On the basis of the staff’s experience with license renewal, the staff has generally concluded that the inner O-ring, the leakoff lines, and the outer O-ring all support the reactor vessel closure head flange pressure boundary. See the letter dated October 27, 1999, from C.I. Grimes of the NRC to D.J. Firth of the Babcock & Wilcox Owner’s Group. In general, the leakoff lines require an aging management review. Please provide a site-specific technical justification for St. Lucie as to why aging management is not required, or perform an aging management review of these components.

2.3.2 Engineered Safety Features Systems

RAI 2.3.2 - 1

During the injection mode for a small break loss-of-coolant accident, a portion of the high pressure safety injection (HPSI) flow is returned to the refueling water tank (RWT) through the bypass line. A section of the bypass line (1-SI-02, location A7, and 2-SI-02, location B4) near the RWT is non-safety-related, and the LRA shows that it is not within the scope of license renewal. If this piping fails and flow is not returned to the RWT, the inventory of the tank could be prematurely exhausted. For both units, there are orifices in the bypass lines which restrict the maximum bypass flow. The Unit 1 bypass flow is 30 gpm per pump (per Table 6.3-2 of the Unit 1 UFSAR) for operation at rated HPSI flow. No specific bypass flow rate could be identified in the Unit 2 UFSAR. For breaks of sufficiently small size, the bypass flow can continue to leak out for a long period of time, potentially exhausting the supply of coolant from the RWT. The failure of the non-safety-related piping in the bypass line could prevent satisfactory accomplishment of the safety-related intended function of the HPSI system. Justify why the piping and valve body components in the bypass piping to the RWT are not within the scope of license renewal and subject to an aging management review.

RAI 2.3.2 - 2

The diagrams of the containment cooling system provided in drawings 1-HVAC-01 and 2-HVAC-02 for Units 1 and 2, respectively, are not sufficiently detailed for the staff to determine the intended system boundaries for license renewal. For example, these drawings do not show whether the applicant considered the duct riser and ring header to be within the scope of license renewal. The notation "to ring header" shown on the downstream side of the containment coolers does not clearly show what components are within the scope of license renewal. On page 6.2-36 of the UFSAR for Unit 2 the applicant states that blowout panels are provided on the duct risers between the fan coolers and ring header to attenuate high-pressure transmission from inside the secondary shield wall through the duct. Similar blowout panels are also described as components of the containment cooling system on page 6.2-50 of the UFSAR for Unit 1. However, blowout panels are not specifically identified as a component or commodity group in Table 3.2-1 of the LRA.

Clarify whether all appropriate containment cooling system components are included within the scope of license renewal and subject to an aging management review, and identify the components and commodity groups that include the ring ducts, risers, and blowout panels. If only a portion of the component cooling water system is within the scope of license renewal and subject to an aging management review, identify the boundary between the in-scope and out-of-scope portions by providing additional textual description, drawings, and/or references (such as designed-basis documents) to supplement the LRA and drawings already provided.

RAI 2.3.2 - 3

The containment isolation system comprises those portions of the containment purge, hydrogen purge (Unit 1), continuous containment/hydrogen purge (Unit 2), service air and containment vacuum relief that have a containment pressure boundary intended function. The Unit 2 containment vacuum relief system air accumulators are shown on license renewal drawing 2-HVAC-01 at location B7 as being within the scope of license renewal. These components are listed in Table 3.3-8 as belonging to the instrument air system. However, LRA Table 2.3-3 does not list drawing 2-HVAC-01 as showing portions of the instrument air system. Justify why these air accumulators are not within the scope of license renewal and subject to an aging management review.

2.4 SCOPING AND SCREENING RESULTS – STRUCTURES

2.4.1 Containments

RAI 2.4.1 - 1

A manway is shown on the top of the steel containment structure at location B5 on general arrangement drawings 8770-G-067 (Unit 1 UFSAR, Figure 1.2-10) and 2998-G-067 (Unit 2 UFSAR, Figure 1.2-10). However, this manway and associated closure bolting and gaskets are not listed in LRA Table 3.5-2. These components appear to form a portion of the containment pressure boundary. Justify why these components are not within the scope of license renewal and subject to an aging management review.

RAI 2.4.1 - 2

In LRA Table 3.5-2, the applicant states that the containment vessel moisture barrier component/commodity group as being made of elastomer (see page 3.5-44). The intended function of this component/commodity group is described as “Provide shelter/protection to safety-related components (including radiation shielding).” Containment vessel moisture barriers and elastomers are also discussed in Sections 3.5.1.4 and 3.5.1.4.1 of the LRA, respectively.

However, a material identified as Ethafoam is shown between the containment vessel and concrete in general arrangement drawings 8770-G-067 (Unit 1 UFSAR, Figure 1.2-10) and 2998-G-067 (Unit 2 UFSAR, Figure 1.2-10) at locations K1, K10, and I15 on both drawings. Ethafoam is a trademark of the Dow Chemical Company for a polyethylene foam product. Explain why Ethafoam components are not within the scope of license renewal and subject to an aging management review.

RAI 2.4.1 - 3

In Section 2.4.1.1.4 of the LRA, the applicant states that two equipment hatches are provided for each containment vessel, a construction hatch and a maintenance hatch. Later in this section it states that two personnel airlocks are provided for each containment vessel. LRA Section 3.5.1.1 (on page 3.5-2) and Table 3.5-2 (on page 3.5-37) list maintenance, personnel and escape hatches. Outside doors for maintenance hatches are also mentioned. However, construction hatches are not explicitly mentioned.

The escape hatches are listed as being in the scope of licensing renewal and subject to an aging management review in Section 3.5.1.1 and Table 3-5-2 of the LRA. Explain why the hatches are not identified in either Section 2.4.1.1.4 or elsewhere in Section 2 of the LRA.

The construction hatch is listed as being in the scope of licensing renewal and subject to an aging management review in Section 2.4.1.1.4 of the LRA. Explain why the hatch is not identified in Section 3.5.1.1 and Table 3.5-2 of the LRA.

<u>RAI 2.4.1 - 4</u>

In Section 2.4.1.2 of the LRA, the applicant states that "the steel Containment Vessel is supported on fill concrete that transfers the loads by bearing to the base slab." The description of the reinforced concrete below groundwater component/commodity group (exterior walls and foundation) provided in Table 3.5-2 (on page 3.5-43) would apply to the base slab. However, it is not clear if this description also applies to fill concrete above the base slab. The fill concrete provides structural support to the containment vessel and, as such, should be within the scope of license renewal and subject to an aging management review. Please indicate whether the fill concrete is within the scope of license renewal and subject to an aging management review, or justify its exclusion.

<u>RAI 2.4.1 - 5</u>

In Section 2.4.1.3 of the LRA, the applicant states that the interior structures of each containment vessel and reactor containment shield building consist of concrete and steel components. However, thermal insulation is present on major reactor, pipe, and valve components; pipe and equipment component supports; and structural enclosures and panels used to shelter instruments and electrical equipment. No insulation material is shown as being within the scope of license renewal in Table 3.5-2 of the LRA. The temperature control intended function provided by insulating materials is important for environmental qualification, as piping and components with degraded insulation will experience additional heat loads and condensation. Justify why insulation is not included in the scope of license renewal and subject to an aging management review.

<u>RAI 2.4.1 - 6</u>

In Section 2.3.3.15 of the LRA, the applicant states that the vent stacks are components of the shield building ventilation systems. These components are not considered as being within the scope of license renewal and subject to an aging management review, for the reasons stated below:

on page 2.3-26 of the LRA:

> "… considering St. Lucie Units 1 and 2 accident analyses assume ground level releases, the plant vent stacks do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore are not within the scope of license renewal."

on page 2.1-4 of the LRA:

"The offsite dose analyses indicate that the radiological consequences of these design basis events, except for the Unit 2 fuel handling accident, represent a small fraction of the 10 CFR Part 100 limits. As a result, SSCs related to the prevention and/or mitigation of these design basis events do not meet the scoping criteria of 10 CFR 54.4(a)(1)(iii). This equipment will still be evaluated relative to the scoping criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3)."

However, the vent stacks are not addressed as structures in the Section 2.4 of the LRA. The vent stacks for both units are shown on the enlarged site plot plan drawing 2998-G-059 (Figure 1.2-2 of both the Unit 1 and Unit 2 UFSARs) at location G7 for Unit 1 and location G10 for Unit 2. The vent stack for Unit 1 is also shown in drawing 8770-G-067 at locations C11 through H11. It appears that approximately 140 feet of this component/structure, with an outer diameter of 6 feet, runs parallel to and is supported by the shield building structure, and sits on top of the penetration area of the reactor auxiliary building.

The vent stacks should be within the scope of license renewal and subject to an aging management review for three reasons:

(1) The vent stacks are substantial structures in close proximity to the shield buildings and directly on top of portions of the reactor auxiliary buildings. The shield and reactor auxiliary buildings are within the scope of license renewal and have safety-related intended functions. Structural failure of the vent stack could result in these buildings being unable to perform their safety-related intended function.

(2) The vent stacks contain and support radiation monitors that are relied upon to function in the event of a waste gas accident. The high-radiation alarms from these monitors are a signal to manually close the control room ventilation intake dampers. (For example, see Amendment 18 in Section 15.4.2-2, of the Unit 1 UFSAR, dated April 2001.)

(3) Blockage of effluent flow from the vent stack as a result of a structural failure could prevent the shield building ventilation system (SBVS) from performing its in-scope intended function.

Non-safety-related structures and components of which a failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1) should be included within the scope of the License Renewal Rule. The failure of the vent stack could potentially damage safety-related SSCs that have a spatial relationship with the vent stack, or could prevent the satisfactory function of the safety-related radiation monitors and the SBVS. Justify why the plant's vent stack structures are not within the scope of license renewal and subject to an aging management review.

3.2 AGING MANAGEMENT REVIEW: EMERGENCY CORE COOLING SYSTEMS

RAI 3.2 - 1

In Table 3.2-2, pages 3.2-14 (Note 1), 3.2-16 (Note 2), and 3.2-17 (Note 1) of the LRA, the applicant states that stainless steel and glass in an environment of hydrazine or sodium hydroxide (NaOH) was determined to have no aging effects requiring management. The applicant is requested to summarize the technical information it identified, and provide the basis and the justification that lead to the determination.

3.4 AGING MANAGEMENT REVIEW: STEAM AND POWER CONVERSION SYSTEMS

RAI 3.4 - 1

For stainless steel components in LRA Table 3.4-1, such as valves, tubing/fittings, filters, and flex hoses that are exposed to an internal air/gas environment, the LRA does not identify any effects requiring aging management. Explain why the LRA does not consider moisture and liquid pooling effects, which can contribute to the aging effects of loss of material as a result of pitting corrosion and cracking.

RAI 3.4 - 2

In tables 3.4-1 and 3.4-2 of the LRA, the applicant indicates that carbon steel bolts are not subject to any aging effects that require aging management. Explain why the effect of humidity in the external environment is not considered to cause aging that leads to a loss of preload.

RAI 3.4 - 3

Provide justification for excluding flow-accelerated corrosion (FAC) as an aging mechanism that can cause wall thinning in auxiliary feedwater piping components. The scope of the FAC program includes main feedwater, blowdown, and main steam and turbine, but not auxiliary feedwater piping and components.

RAI 3.4 - 4

In Tables 3.4-1 and 3.4-2 of the LRA, the applicant identified the Boric Acid Wastage Surveillance Program to manage the aging effects in piping, valves and fittings to ensure that boric acid corrosion does not lead to degradation of the pressure boundary. The Boric Acid Wastage Surveillance Program manages aging effects associated with aggressive chemical attack. Provide a discussion of how this program manages aging effects associated with elevated temperatures and stress levels to prevent loss of preload in mechanical bolting.

3.5 AGING MANAGEMENT REVIEW: STRUCTURES AND STRUCTURAL COMPONENTS

RAI 3.5 - 1

Considering the vulnerability of concrete structural components, the staff has required previous license renewal applicants to implement an aging management program to manage the aging of these components. The staff's position is that cracking, loss of material, and change in material properties are plausible and applicable aging effects for concrete components inside containment, as well as for other structures outside containment. For inaccessible concrete components, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive; however, the staff requires inspection through an aging management program for all other concrete components. Provide justification for concluding that there are no applicable aging effects for (1) reinforced concrete walls, slabs, trenches, foundations, shields, and roofs above groundwater in outdoor and containment air environments and (2) reinforced concrete interior shield walls, beams, slabs, missile shields, and equipment pads inside containment.

RAI 3.5 - 2

Loss of material is considered to be an applicable aging effect for galvanized carbon steel components in a "wetted" outdoor environment; however, the LRA does not list any aging effects for galvanized carbon steel components in an outdoor environment. Zinc-based coating of carbon steel may not provided complete protection from corrosion for components located in a humid environment. Provide justification for concluding that there are no aging effects for galvanized carbon steel components in an outdoor environment. In addition, distinguish between a "wetted" outdoor environment and an outdoor environment.

RAI 3.5 - 3

LRA Tables 3.5-2 through 3.5-16 do not identify any aging effects for the following components:

- silicone fuel transfer tube penetration flexible membranes (in annulus) (Table 3.5-2)
- lubrite sliding supports (Table 3.5-2)
- silicone mechanical penetrations (Table 3.5-8)
- carbon steel plate fire-sealed isolation joint (Table 3.5-8)

Specifically, the staff does not agree with the applicant's characterization of the radiation-resistant silicon rubber membrane material used in the fuel transfer tubes, since movements attributable to temperature fluctuations in the containment and fuel handling building could result in misalignment and loss of seal. Provide justification as to why these membrane seals (or the transfer tubes in the annular space) should not have a nominal aging management program to ensure the effectiveness of the seals during the period of extended operation.

For the lubrite plates, provide their location(s), including the operating environment (temperature, humidity, and neutron flux) and loads (static and vibratory) to which they are subjected. Include occasional exposure to any degrading environments, such as borated water spills or leakage. Also, provide information related to the manufacturer-suggested life of the product under the expected operating conditions.

For the silicone mechanical penetrations in the fire-rated assemblies, provide justification for concluding that increased hardness and shrinkage are not applicable aging effects.

For the carbon steel fire-sealed isolation joint, provide justification for concluding that loss of material is not an applicable aging effect.

RAI 3.5 - 4

Loss of material is considered to be an applicable aging effect for carbon steel components in indoor - not air conditioned and outdoor environments. However, loss of material is not considered to be applicable for carbon steel components located in indoor - air conditioned environments. Provide justification for making this distinction for carbon steel components in these different environments.

RAI 3.5 - 5

The LRA does not list any applicable aging effects for earthen canal dikes in the intake, discharge, and emergency cooling canals (Table 3.5-10). Earthen water-control structures are susceptible to loss of material and loss of form resulting from erosion, settlement, sedimentation, waves, currents, surface runoff, and seepage. Provide justification for concluding that loss of material and loss of form are not applicable aging effects for the earthen canal dikes.

RAI 3.5 - 6

The LRA does not list any applicable aging effects for stainless steel fuel transfer tubes and expansion bellows located in a containment air environment. Considering prior industry experience with cracking of expansion bellows, justify why cracking is not considered to be an applicable aging effect for stainless steel fuel transfer tubes and expansion bellows. Are these bellows subjected to a periodic containment leak rate testing program?

RAI 3.5 - 7

Given the potential for clogging of the recirculation sump screens, provide past operating experience with clogging from peeling paint or other debris. In addition, discuss any aging management programs that will be used to ensure the effectiveness of protective coatings throughout the period of extended operation.

RAI 3.5 - 8

Referring to Section 3.5.2.2.2 of the LRA, discuss St. Lucie's operating experience regarding the effectiveness of its application of the impressed current cathodic protection system to prevent the corrosion of carbon steel in fluid structural components that are exposed to raw water. Is the impressed current cathodic protection system used for items other than the sheet piling? If yes, briefly discuss the operating experience with respect to the effectiveness of these applications.

RAI 3.5 - 9

To demonstrate the potential for aging of concrete components below groundwater, provide the following information:

(1) average levels of contaminants (chloride and sulfates) and the pH level in the ground water soil surrounding below-grade concrete members

(2) grade elevations and the ground-water level fluctuations in the areas surrounding below-grade concrete members

(3) existing condition of concrete structural members exposed to groundwater

RAI 3.5 - 10

Provide a more detailed description of FPL provisions for inspecting inaccessible structural components. Specifically, for some inaccessible structural components, there may not be a matching accessible component with the same material and environment to provide an indication of the condition of the inaccessible component. In NUREG 1611, "Aging Management of Nuclear Power Plant Containments for License Renewal," issued September 1997, the staff specifies that applicants for license renewal need to evaluate on a case-by-case basis, the acceptability of inaccessible areas, even though conditions in accessible areas may not indicate the presence of degradation to components in inaccessible areas.

RAI 3.5 - 11

In Section 3.5.2.4.2 of the LRA, the applicant identified cracking as an aging effect requiring management for miscellaneous structural components; however, in the paragraphs preceding this conclusion, the LRA states that cracking is not considered to be an applicable aging effect. In addition, LRA Tables 3.5-2 through 3.5-16 do not list cracking as an applicable aging effect for any miscellaneous structural components. Please resolve this discrepancy.

RAI 3.5 - 12

In Section 3.5.1.3 of the LRA, the applicant concluded that masonry walls do not need aging management during the period of extended operation. However, cracking and degradation of masonry walls is a generic observation at nuclear power plants. NRC Information Notice 86-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," and the findings of walkdowns at the nuclear power plants included in the resolution of Unreviewed Safety Issue A-46, indicate that in-scope masonry walls need periodic inspections. Please provide information regarding the basis for not developing a masonry wall aging management program.

3.6 AGING MANAGEMENT REVIEW: ELECTRICAL AND INSTRUMENTATION AND CONTROLS

RAI 3.6 - 1

Sections 3.6.1.1.4 of the LRA evaluates the applicable aging effects for electrical components that can be expected to occur as a result of radiation. The applicant states that the DOE Cable Aging Management Guide, Section 4.1.4, provides a threshold value and a moderate dose for various insulating materials. The threshold value is the amount of radiation that causes incipient to mild insulation damage. Once this threshold is exceeded, damage to the insulation increases from mild to moderate or severe as the total dose increases.

The moderate damage value indicates the value at which the insulating material has been damaged but is still functional. St. Lucie Units 1 and 2 evaluations use the moderate damage dose from the DOE Cable Aging Management Guide as the limiting radiation value shown in Table 3.6-3 of the LRA. The maximum dose shown in Table 3.6-3 includes the maximum 60-year normal exposure inside containment. The applicant concludes that because the maximum operating radiation dose to cable insulation will not exceed the moderate damage doses no aging management are required for radiation. Section 3.1.1.5 of the LRA evaluates the aging effects applicable for electrical components due to heat and oxygen. The applicant states that it developed a maximum operating temperature for each insulation type based on cable applications at St. Lucie Units 1 and 2. The maximum operating temperature indicated in LRA Table 3.6-4 incorporates a conservative value for self-heating for power applications combined with the maximum design ambient temperature. The applicant used the Arrhenius method, as described in EPRI NP-1558, to determine the maximum continuous temperature to which insulation can be exposed so that the material has an indicated “endpoint of 60 years.” The applicant concludes that a comparison of the maximum operating temperature to the maximum 60-year continuous use temperature for the various insulation materials indicates that all of the insulation material used in low-and medium-voltage power cables and connections can withstand the maximum operating temperature for at least 60 years.

In most areas within a nuclear power plant, the actual ambient environments (e.g. temperature, radiation, or moisture) are less severe than the nominal plant environment. However, in a limited number of localized areas, the actual environments may be more severe than the nominal plant environment. Conductor insulation materials used in cable and connections may degrade more rapidly than expected in these adverse localized environments and require aging management. The purpose of the aging management program is to provide reasonable assurance that the intended functions of electrical cables and connections exposed to adverse localized environments caused by radiation, heat, or moisture will be maintained to be consistent with the current licensing basis through the period of extended operation.

Therefore, for non-environmentally qualified (non-EQ) cables, connections (connectors, splices, and terminal blocks) are within the scope of license renewal and are located in the containment or the reactor auxiliary building, describe the aging management program for accessible and inaccessible electrical cables and connections exposed to an adverse localized environmental caused by heat, radiation, or moisture.

RAI 3.6 - 2

Exposure of electrical cables to localized environments caused by heat, radiation, or moisture can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument loop. Visual inspection may not be sufficient to detect aging degradation from heat, radiation, or moisture in the instrumentation circuits with sensitive, low-level signals. Because low-level signal instrumentation circuits may operate with signals that are normally in the pico-amp or less, they can be affected by extremely low levels of leakage current. These low levels of leakage current may affect instrument loop accuracy before the adverse localized changes are visually detectable. Routine calibration tests performed as part of the plant's surveillance test program can be used to identify the potential existence of this aging degradation. Provide a description of your aging management program that will be relied upon to detect this aging degradation in sensitive, low-level signal circuits.

4.0 TIME-LIMITED AGING ANALYSES (TLAAs)

4.1 Identification of TLAAs

RAI 4.1 - 1

Table 4.1-1 of the LRA does not identify pipe break postulation based on cumulative usage factor (CUF) as a TLAA. Section 3.6.2.2.1 of the St. Lucie Unit 2 UFSAR describes the criteria used to provide protection against pipe whip inside the containment. Part of the criteria specifies the postulation of pipe breaks at locations where the CUF exceeds 0.1. Although the fatigue usage factor calculation was identified as a TLAA, the pipe break criterion was not identified as a TLAA. However, the usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3 and, therefore, the staff considers the associated criteria for pipe break postulation a TLAA. Provide a description of the TLAA performed to address the pipe break criteria for St. Lucie Unit 2. Also identify any pipe break postulations based on CUF at St. Lucie Unit 1 and describe the TLAA performed for these locations. Indicate how these TLAAs meet the requirements of 10 CFR 54.21(c).

Table 4.1-1 of the LRA does not identify fatigue of the reactor coolant pump flywheel as a TLAA. Indicate whether fatigue crack growth calculations were performed for the St. Lucie Unit 1 and 2 reactor coolant pump flywheels. If fatigue crack growth calculations were performed for these pump flywheels, describe the TLAA evaluations and indicate how these TLAAs meet the requirements of 10 CFR 54.21(c).

4.3 Metal Fatigue

RAI 4.3 - 1

In Section 4.3.1 of the LRA, the applicant discusses its evaluation of the fatigue TLAA for ASME Class 1 components. The discussion indicates that based on its review of the plant's operating history, the applicant concluded that the number of cycles assumed in the design of the ASME Class 1 components is conservative and bounding for the period of extended operation. Section 3.9 of the UFSARs for St. Lucie, Units 1 and 2, provides a listing of transient design conditions and associated design cycles. Provide the following information for each transient described in the UFSARs:

(1) the current number of operating cycles and a description of the method used to determine the number and severity of the design transients from the plant's operating history

(2) the number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years

(3) a comparison of the design transients listed in UFSAR with the transients monitored by the Fatigue Monitoring Program (FMP) as described in Section B3.2.7 of the LRA; an identification of any transients listed in the UFSAR that are not monitored by the FMP; and an explanation of why it is not necessary to monitor these transients

RAI 4.3 - 2

In Section 4.3.1 of the LRA, the applicant indicates that the pressurizer surge lines were reanalyzed in response to NRC Bulletin 88-11, "Pressurizer Surge Line Stratification." Identify whether calculations that meet the definition of a TLAA were performed in response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." Describe the actions that will be taken to address NRC Bulletin 88-08 throughout the period of extended operation.

RAI 4.3 - 3

In Section 4.3.3 of the LRA, the applicant discusses its evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion references the fatigue-sensitive component locations for an older vintage Combustion Engineering plant identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The LRA indicates that these fatigue-sensitive component locations were evaluated for St. Lucie, Units 1 and 2. The LRA also indicates that the later environmental fatigue correlations contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," were considered in the evaluation. Provide the results of the usage factor evaluation for each of the six component locations listed in NUREG/CR-6260.

4.4 EQ of Electrical Equipment

RAI 4.4 - 1

In Section 4.4 of the LRA, the applicant indicates that environmental qualification (EQ) acceptance criteria for temperature is the component's maximum required operating temperature. If the maximum operating temperature of a component for normal plant conditions is equal to or less then the temperature to which the component was qualified by test, the component is considered qualified. With a component's normal operating temperature equal to the temperature to which it was tested to demonstrate EQ, explain how temperature margin (or other conditions or attributes of the Arrhenius method) has been utilized to account for uncertainties of the Arrhenius method.

Explain how margin has been maintained to account for uncertainties of the Arrhenius method. Describe the margins built into the qualification process that will remain in the qualification process after re-analysis for 60 years. Explain why these remaining margins can be considered sufficient to address the uncertainties of the Arrhenius method for establishing qualified life.

RAI 4.4 - 2

Explain and clarify how the electro-mechanical components of a normally energized continuous duty motor are maintained qualified for 40 years and 60 years of continuous operation.

4.5 Containment and Penetration Fatigue Analysis

RAI 4.5 - 1

In Section 4.5.1of the LRA, the applicants states that the containment vessels are designed in accordance with Section III of the ASME Boiler and Pressure Vessel Code. The LRA indicates that the design criteria provide assurance that the specified leak rate will not be exceeded under the design-basis accident conditions. Discuss how the design criteria applied to the steel vessels provide this assurance.

RAI 4.5 - 2

In Section 4.5.2 of the LRA, the applicant states that containment penetration bellows are specified to withstand a lifetime total of 7,000 cycles of expansion and compression attributed to maximum operating thermal expansion, and 200 cycles of other effects.

(1) Show that the specified cycles bound the period of extended operation.

(2) For Type I and Type III containment penetrations, describe the methods used to provide assurance that the penetration bellows will withstand these specified cycles under the corresponding thermal expansion and other loads for the extended period of operation.

RAI 4.5 - 3

State whether the containment penetration bellows are included within the scope of the St. Lucie Fatigue Monitoring Program, referred to in Sections 4.3.1 and B.3.2.7 of the LRA. If not, provide justification for not including these components in the program.

4.6.3 Unit 1 Core Support Barrel Repairs

RAI 4.6.3 - 1

Provide a detailed description of the fatigue analysis of the core support barrel middle cylinder with the expandable plugs, including the design thermal transients and cycles. Confirm that the fatigue evaluation meets the ASME Section III Class 1 fatigue criteria for the life of the plant.

RAI 4.6.3 - 2

Provide the source and basis for the data and information that was used to assess irradiation induced relaxation of the plug preload, which is expected to occur in the core support barrel expandable plugs at the end of 60 years of reactor operation.

RAI 4.6.3 - 3

Provide a detailed description of the core support barrel plug preload analysis based on irradiation induced stress relaxation, showing that the expandable plugs will continue to perform their function given the predicted fluence, operating temperature, operating hydraulic loads, and thermal deflections for the period of extended operation.

B.3.1 NEW AGING MANAGEMENT PROGRAMS

B.3.1.3 Pipe Wall Thinning Inspection Program

RAI B.3.1.3 - 1

Provide the specific section in the American National Standards Institute (ANSI) B31.7, that will be the basis for calculating the required minimum wall thickness for Unit 1 auxiliary feedwater piping.

RAI B.3.1.3 - 2

Provide the specific section in ASME Code, Section III, that will be the basis for calculating the required minimum wall thickness for the Unit 2 auxiliary feedwater and component cooling water piping.

RAI B.3.1.3 - 3

In Section B.3.1.3 of the LRA, the applicant states that the pipe wall thinning inspection program is credited as the aging management program for managing the internal loss of material attributed to erosion. Later, in describing the monitoring and trending aspect of the program, the applicant states, “The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, corrosion rates, and minimum required wall thickness.” Explain the apparent inconsistency between erosion rates and corrosion rates. In addition, explain how those rates are determined.

B.3.2 EXISTING AGING MANAGEMENT PROGRAMS

B.3.2.2 ASME Section XI Inservice Inspection Programs

RAI B.3.2.2 - 1

In Table 3.5-2 of the LRA, the applicant indicates that the containment bellows are covered by the inservice inspection program established in accordance with Section XI, Subsection IWE, of the ASME Boiler and Pressure Code. Recognizing the susceptibility of the bellows to cracking (see NRC Information Notice 92-20) as a result of transgranular stress corrosion cracking (TGSCC), provide the operating experience related to the condition of the bellows at St. Lucie, Units 1 and 2. Also, provide the method used to detect degradation of the bellows.

RAI B.3.2.2 - 2

In the GALL aging management program XI.S4, “10 CFR Part 50, Appendix J,” Section 1, “Scoping of Program,” the staff specifies the options for leakage testing of containment isolation valves. The options are to conduct testing (1) under the Type C test of Appendix J, or (2) along with the tests of the systems containing the containment isolation valves. Which option will the applicant implement during the extended period of operation?

RAI B.3.2.2 - 3

Summarize the operating experience related to the leakage rate testing of the pressure-retaining containment components for St. Lucie, Units 1 and 2.

B.3.2.8 Fire Protection Program

RAI B.3.2.8 - 1

In Section B.3.2.8, “Scope,” of the LRA, the applicant states that the Fire Protection program will manage the aging effects of loss of material due to corrosion. Provide justification for excluding loss of material due to micro-biologically influenced corrosion or biofouling of carbon steel and cast-iron components in fire-protection systems exposed to water.

In addition, clarify the information on page 3.3-11 of the LRA that indicates that the Fire Protection Program is consistent with the corresponding programs in the GALL report.

RAI B 3.2.8 - 2

In Section B.3.2.8, “Parameters Monitored or Inspected,” of the LRA, the applicant states that surface conditions are visually monitored. Provide the percentage for each type of penetration seal that would be inspected during each refueling outage. Also, provide the inspection frequencies for the visual and function tests of fire doors and seals.

RAI B.3.2.8 - 3

Discuss your program for internal inspections of fire protection piping as stated in Chapter XI.M27, “Fire Water Systems,” of the Gall report. Explain how the program will detect wall thinning due to internal corrosion. Opening the system results in introducing oxygen, that may contribute to the initiation of general corrosion. Explain why the use of non-intrusive means of measuring wall thickness, such as ultrasonic inspection, are not used to manage this aging effect.

RAI B.3.2.8 - 4

Discuss the inspection activities that provide the reasonable assurance that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation.

RAI B.3.2.8 - 5

In Section B.3.2.8, “Operating Experience and Demonstrations,” of the LRA, the applicant states that the Fire Protection Program has been subjected to periodic internal and external assessments. Discuss the significant recent enhancements as a result of these assessments. Indicate whether or not these enhancements have received NRC approval.

RAI B.3.2.8 - 6

The 50-year service life of sprinkler heads does not necessarily equal the 50th year of operation in terms of licensing. The service life is defined from the time the sprinkler system is installed and functional. The staff interpretation, in accordance with National Fire Protection Agency (NFPA) 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” is that testing should be performed prior to 50 years of sprinkler system service life, not at year 50 of plant operation. The staff position for this approach results in an applicant performing three such inspections over a 60-year period; the first before the end of the current operating term, the second after the 50-year sprinkler head testing, and the third after the first 10-year follow-up sprinkler head testing. Discuss your inspection plans for the sprinkler heads during the current operating term, as well as during the period of extended operation.

B.3.2.10 Intake Cooling Water Inspection Program

RAI B.3.2.10 - 1

The periodic surveillance and preventive maintenance program is an existing program that will be enhanced with regard to the scope of specific inspections. Provide applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the intake cooling water system: stainless steel, carbon steel and cast iron intake cooling water pumps; rubber intake cooling water pump expansion joints; and aluminum-bronze pump discharge valves exposed externally to the raw water environment. The applicant provided this information for other components in the intake cooling water system.

RAI B.3.2.10 - 2

For those structures that are inaccessible for inspection through the systems and structures monitoring program, an inspection of structures with similar materials and environments may be indicative of aging effects. Several components in the intake cooling water system credit this program for managing loss of material in the raw water environment. Provide the applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the intake cooling water system: cast iron, carbon steel, bronze, monel, and stainless steel valves, piping, tubing, and fittings; stainless steel orifices; and stainless steel thermowells exposed internally to the raw water environment.

RAI B.3.2.10 - 3

Identify and describe the specific plant procedures and applicable documents which contain detailed guidance related to performance monitoring, testing and tube examinations of the heat exchangers. Also provide the acceptance criteria and the bases for acceptance of the inspection results.

RAI B.3.2.10 - 4

In the UFSAR for St. Lucie Unit 1, the applicant states that the component cooling water heat exchanger components exposed to raw water are protected by sacrificial anodes located in the heat exchangers. Are these sacrificial anodes credited in reducing corrosion or cracking? Identify and describe the program that provides for inspection of these anodes.

RAI B.3.2.10 - 5

In Section B.3.2.10 of the LRA, applicant states that the internal linings on piping and other components are visually inspected for degradation. What criteria are used to determine which components should be inspected? Do these inspections include inspection of lining on the inside surface of fittings such as elbows? This information is requested because the field experience described in IE Information Notice No. 85-24, "Failures of Protective Coatings in Pipes and Heat Exchangers," indicates that the interior protective lining on elbows are more susceptible to degradation than that on straight piping.

RAI B.3.2.10 - 6

For the buried or submerged carbon steel piping in intake cooling water system, which is externally exposed to aggressive external environments, the Intake Cooling Water System Inspection Program does not provide sufficient information about how the applicant plans to prevent, mitigate, detect, or trend loss of material caused by corrosion at the outside surface of these piping. Do you plan to use the wall thickness measurements as indicators of loss of material at the external surface of buried and submerged carbon steel piping? If so, then describe how these wall thickness will be measured.

B.3.2.11 Periodic Surveillance and Preventive Maintenance Program

RAI B.3.2.11 - 1

In Section B.3.2.11, “Monitoring and Trending,” of the LRA, the applicant states”

> The inspections, replacements, and sampling activities associated with this program are performed on a specific frequency as listed in administrative procedures, and that the results of these activities are documented. The program includes various frequencies depending upon the specific component and aging effect being managed, and plant operating experience.

Since this is an existing program, provide a brief description of how frequently the inspections are conducted and components are replaced. For example, for *Preventive Actions*, the applicant states that preventive measures include charging pump block internal inspection (Unit 2 only), oil sampling and water removal, and replacement of specific structural components and component groups are based on operating experience. In *Parameters Monitored or Inspected*, the applicant states that certain intake cooling water system components are replaced on a given frequency based on operating experience. Identify the specific frequencies of those component inspections and replacements, including how operating experience is used to determine the frequencies.

RAI B.3.2.11 - 2

The applicant provided limited information regarding the different attributes of the periodic surveillance and preventive maintenance program as far as aging management of the instrument air system components is concerned.

(1) Provide information about whether the program is based on the Instrument Society of America's Standard ISA-S7.0.1-1996, "Quality Standards for Instrument Air." Specifically, discuss whether the moisture content and particulate size in the instrument air are continuously monitored. What are the acceptance criteria for particulate size and oil content in the instrument air? How often is the system sampled to ensure that air quality is maintained?

(2) Provide information about the inspection and testing frequency used for the instrument air system components. Does the program follow the recommendations made by the industry report issued by the Electric Power Research Institute (EPRI) as EPRI NP-

7079, "Instrument Air Systems – A Guide for Power Plant Maintenance Personnel," 1990, or its 1998 revision (i.e., EPRI/NMAC TR-108147, 1998)?