DRAFT

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U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Response to NRC Request for Additional Information for Review of the
St. Lucie Units 1 and 2 License Renewal Application

By letters dated July 1, 2002 and July 18, 2002, the NRC requested additional information regarding the St. Lucie Units 1 and 2 License Renewal Application (LRA) Sections 2.0, 3.0, 4.0 and Appendix B. Attachment 1 to this letter contains FPL's responses to the requests for additional information (RAIs) associated with the Aging Management Review Results, Section 3.0 of the LRA. Responses to RAIs associated with Section 3.3 Aging Management Review Results − Auxiliary Systems are addressed in FPL Letter L-2002-159 dated XXXX XX, 2002.

Should you have any further questions, please contact S. T. Hale at (772) 467-7430.

Very truly yours,

D. E. Jernigan
Vice President
St. Lucie Plant

DEJ/STH/hlo
Attachment (1)

Enclosure 6

St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389

Response to NRC Request for Additional Information Regarding the License Renewal Application, Section 3.0 - Aging Management Review Results.

STATE OF FLORIDA)
) ss
COUNTY OF ST. LUCIE)

D. E. Jernigan being first duly sworn, deposes and says:

That he is Vice President − St. Lucie of Florida Power and Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information and belief, and that he is authorized to execute the document on behalf of said Licensee.

____
D. E. Jernigan

Subscribed and sworn to before me this

______ day of ________________, 2002.

____

____
Name of Notary Public (Type or Print)

D. E. Jernigan is personally known to me.

cc: U.S. Nuclear Regulatory Commission, Washington, D.C.

Chief, License Renewal and Standardization Branch
Project Manager − St. Lucie License Renewal
Project Manager - St. Lucie

U.S. Nuclear Regulatory Commission, Region II
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ATTACHMENT 1
RESPONSE TO NRC REQUESTS FOR ADDITIONAL INFORMATION FOR REVIEW OF THE ST. LUCIE UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

3.1 Aging Management Review: Reactor Coolant System

3.1.4 Reactor Vessel Internals

RAI 3.1 - 1

In LRA Section 3.1.4, “Reactor Vessel Internals Inspection Program,” the applicant indicates that this program is plant-specific and is intended to supplement the reactor vessel internals inspections required by the inservice inspection programs conducted under Section XI of the Boiler and Pressure Vessel Code promulgated by the American Society of Mechanical Engineers (ASME). The applicant further indicates that it will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1, and this report describe the St. Lucie inspection plan. The staff expects the inspection plan to include the St. Lucie Unit 1 long-term inspections and inservice monitoring as described in Subsections 5.1 and 5.2 of the “St. Lucie Unit 1 − Thermal Shield Recovery Program Final Core Support Barrel Inspection Report (Post-Cycle 6),” L-86-181, dated April 25, 1986. Confirm this expectation, or provide justification for its exclusion.

FPL Response

FPL letter L-86-181, dated April 25, 1986, describes the results of the St. Lucie Unit 1 short-term core support barrel (CSB) inspection performed during the refueling outage following Cycle 6. A description of long range inspections and in-service monitoring activities for the CSB was included in the letter. At this time, FPL intends to include these inspection and monitoring activities in the scope of the St. Lucie Unit 1 Reactor Vessel Internals Inspection Program. As indicated in Appendix B, Subsection 3.1.4 of the LRA, FPL will submit an integrated report describing the Reactor Vessel Internals Inspection Program to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1. The integrated report will contain a description of the inspection plan.

3.1.6 <u>Steam Generators</u>

<u>RAI 3.1 - 2</u>

In LRA Table 3.1-1 on page 3.1-66, the applicant discussed aging management of U-tubes, but not tubes. In Sections 3.1.6.2.1 and 3.1.6.2.2 of the LRA, the applicant discusses aging issues related to tubes. Clarify whether the U-tubes identified in Table 3.1-1 represent the low-row (short radius) U-bend tubes or the entire tube bundle.

<u>FPL Response</u>

The St. Lucie Units 1 and 2 steam generators are of an inverted U-tube design. As such, the terms “U-tubes” and “tubes” are used interchangeably in Section 3.1.6 and Table 3.1-1 of the LRA. Use of either term is intended to represent all tubes within the tube bundle.

RAI 3.1 - 3

In Table 3.1-1, “Reactor Coolant Systems,” of the LRA, the staff identified that certain aging effects, which apply to steam generator components, are absent. Explain or justify why the following aging effects are not specified in Table 3.1-1:

On page 3.1-69 of the LRA, the applicant specified that the external surface of the primary instrument nozzles may be affected by leaking borated water. However, there was no aging effect and associated aging management program applied to the primary instrument nozzles under this external environment.

Clarify why loss of material due to boric acid corrosion (on the external surface) was not an aging effect applied to the secondary manway and handhold closure covers, shell assembly, feedwater nozzles and safe ends, steam outlet nozzles and safe ends, and primary heads.

Table 3.1-1 of the LRA identified cracking as an aging effect for Unit 1 stainless steel tube support lattice bars, but did not identify cracking Unit 2 carbon steel tube support lattice bars. Carbon steel is susceptible to cracking in the treated water environment. Clarify why cracking is not applicable to the Unit 2 tube support lattice bars.

Clarify why the wall thinning attributable to erosion was not applicable as an aging effect for secondary manways and handholds.

FPL Response

As indicated in Table 3.1-1 of the LRA (page 3.1-69), the primary instrument nozzles are fabricated from either Alloy 600 or Alloy 690 material. Alloy 600 and 690 are nickel-based alloys, which are not susceptible to boric acid wastage. As such, there is no aging effect requiring management for the primary instrument nozzles exposed to an external environment of borated water leaks.

As indicated in Table 3.1-1 of the LRA (page 3.1-69), the primary heads are potentially exposed to an external environment of borated water leaks. Accordingly, loss of material is identified as an aging effect requiring management and the Boric Acid Wastage Surveillance Program provides assurance that this aging effect is managed for the period of extended operation.

The steam generator secondary manway and handhole closure covers, shell assemblies, feedwater nozzles and safe ends, and steam outlet nozzles and safe ends are not considered to be susceptible to borated water leaks since they are isolated from potential reactor coolant system (RCS) leaks by the steam generator geometry. The geometry of the steam generator primary head and the physical distance between the primary manways and the upper and lower shells essentially eliminates the potential for boric acid exposure to these parts. This conclusion is consistent with the results presented in Chapter IV.D1 of the GALL Report (LRA Reference 3.1-1).

Carbon steel components are not considered to be susceptible to cracking in a secondary side treated water environment. As such, cracking is not identified as an aging effect requiring management for the St. Lucie Unit 2 carbon steel tube support lattice bars. As indicated in Table 3.1-1 of the LRA (page 3.1-68), this conclusion is consistent with that identified for Item IV D1.2.2 (tube support lattice bars) of the GALL Report (LRA Reference 3.1-1).

The design of the secondary manways and handholes precludes the potential for wall thinning due to erosion. The secondary manways and handholes are located in areas of large cross section where velocity is low and erosion is not an aging concern. Plant specific experience has confirmed that these components are not susceptible to this aging effect.

RAI 3.1 - 4

In NRC Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Welds in Steam Generators," the staff states that if general corrosion or pitting of the steam generator shell is known to exist, the inspection program in Section XI of the ASME Code may not be sufficient to differentiate isolated cracks from inherent geometric conditions of the shell. Describe additional inspection procedures for the upper and lower steam generator shells, if general corrosion or pitting exists in the St. Lucie steam generator shells.

FPL Response

As indicated in Section 3.1.6.2.2 and Table 3.1-1 of the LRA (pages 3.1-34 and 3.1-66, respectively), loss of material due to general corrosion and pitting corrosion has been identified as an aging effect for internal surfaces of carbon steel and low alloy steel components on the steam generator secondary side, including the upper and lower shells. General corrosion and pitting corrosion of the steam generator upper and lower shells is mitigated by maintaining adequate secondary-side chemistry controls via the Chemistry Control Program.

To date, loss of material due to general corrosion and pitting corrosion of the St. Lucie Units 1 and 2 steam generator upper and lower shells has not been experienced. Accordingly, no additional inspection procedures are required at this time.

RAI 3.1 - 5

Discuss tube plugs installed in the Unit 1 and 2 steam generators, such as plug type and operating experience. Confirm that all tube plugs use thermally treated Alloy 690 material.

FPL Response

The original St. Lucie Unit 1 steam generators were replaced in 1997. The replacement steam generators utilize mechanical tube plugs fabricated from thermally treated Alloy 690 material. To date, there has been no evidence of tube plug degradation and no tube plugs have been replaced.

The St. Lucie Unit 2 steam generators utilize a combination of welded plugs and hydraulically expanded plugs. All hydraulically expanded tube plugs currently installed in the St. Lucie Unit 2 steam generators are fabricated from thermally treated Alloy 690 material. Approximately 50 tubes in the Unit 2 steam generators were plugged during manufacture (i.e., shop plugs) with welded tube plugs fabricated from Alloy 600 material. One of these welded shop plugs was replaced in 1985 due to leakage. The Alloy 600 material was inadvertently omitted from Table 3.1-1. Table 3.1-1 is revised as noted below.

TABLE 3.1-1
REACTOR COOLANT SYSTEMS

Component/ Commodity Group ALL Reference]	led Function	laterial	nvironment	ing Effects Requiring anagement	gram/Activity
Steam Generators					
Internal Environment					
ugs .3]	e boundary	0 0 TT	water – primary	g	Generator Integrity n try Control n

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.

FPL Response

The bases for the conclusions provided by Note (1) and Note (2) can be found in the Metals Handbook, 9th Edition Volume 13 and in the National Association of Corrosion Engineers Corrosion Data Survey, Fifth Edition. Tables 35 and 37 on pages 1174 and 1175 of the Metals handbook show a negligible corrosion rate (i.e., less than 0.1 mils/year) for stainless steel in the sodium hydroxide (NaOH) environment applicable to St. Lucie Unit 1 Containment Spray components (i.e., 28.5-30.5 % by weight solution NaOH and maximum temperature of 100°F). Additionally, as discussed on page 1175 of the Metals Handbook, the potential for stress corrosion cracking (SCC) in a NaOH environment is avoided by maintaining temperature below 200°F. Since the operating temperature of the components exposed to the NaOH internal environment is a maximum of 100°F, there are no aging effects requiring management for these components. Similarly, based upon page 100 of the National Association of Corrosion Engineers Corrosion Data Survey, the corrosion rate is negligible for stainless steel in the hydrazine environment applicable to St. Lucie Unit 2 Containment Spray components (i.e., 25.4 % by weight solution hydrazine and normal operating temperature less than 100°F).

Finally, these conclusions are supported by plant specific operating experience, in that neither stainless steel nor glass in the environments of hydrazine or sodium hydroxide have experienced any adverse aging effects.

3.4 Aging Management Review: Steam And Power Conversion Systems

RAI 3.4 - 1

For stainless steel components in LRA Table 3.4-1[sic: 2], 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.

FPL Response

The only stainless steel components exposed to an air/gas environment in Steam and Power Conversion Systems are those listed on LRA Table 3.4-2 (page 3.4.14). For both units, the potential for moisture and liquid pooling effects do not exist because the air/gas environment is high purity nitrogen as indicated in Note 1 on LRA Table 3.4-2 (page 3.4.14). As described in LRA Appendix C, Subsection 4.1.3 (page C-8), when wetted conditions were determined to exist, the environment description was amended accordingly and applicable aging effects were addressed. As discussed in Sections 5.1 and 5.2 of LRA Appendix C, moisture and contaminants must be present for pitting or stress corrosion cracking to occur. Therefore, the stainless steel components exposed to an air/gas environment identified in RAI 3.4-1 are not susceptible to loss of material or cracking.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

Although the LRA identifies bolting (mechanical closures) material as carbon steel, the actual bolting standard for St. Lucie Units 1 and 2 piping and components is low alloy steel ASTM A193, Grade B7. This material provides increased corrosion resistance over plain carbon steel. The bolting associated with Main Steam, Auxiliary Steam, Turbine, Main Feedwater and Steam Generator Blowdown is typically in a dry environment, coated with a lubricant, and exposed to temperatures greater than 212°F. Therefore, moisture is not present on the surfaces of piping or associated bolting, and as a result loss of material due to general corrosion does not require management.

Review of the St. Lucie plant experience, which was performed as part of the aging management review (AMR) process, confirmed that no loss of mechanical closure integrity has occurred due to general corrosion of bolting. Review of industry experience also confirms that general corrosion of bolting has not been a major concern and therefore is not an aging effect requiring management.

Aging effects associated with bolting are described in the LRA, Appendix C, Section 5.4 (pages C-16 and C-17), Loss of Mechanical Closure Integrity. The only aging effect determined to require management associated with bolting is loss of mechanical closure integrity due to boric acid corrosion for components in proximity to borated water systems.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

The St. Lucie Flow Accelerated Corrosion Program is based on industry consensus standard, NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program". This document states in Section 4.2.2 that:

Some susceptible systems, or portions of systems, can be excluded from further evaluation due to their relatively low level of susceptibility. Based on both laboratory and plant experience, the following systems can be safely excluded from further evaluation:

Systems with no flow, or those that operate less than 2% of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F less than 2% of the plant operating time."

Auxiliary Feedwater at St. Lucie is operated less than 2% of the plant operating time. As a result, loss of material due to flow accelerated corrosion is not an aging effect requiring management for Auxiliary Feedwater.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

The Boric Acid Wastage Surveillance Program is not credited for managing aging effects associated with elevated temperatures and stress levels to prevent loss of pre-load in mechanical joints.

As discussed in LRA Appendix C, Subsection 5.4 (pages C-16 and C-17), "Loss of Mechanical Closure Integrity", the effect of loss of pre-load resulting from temperature effects and cyclic loading is external leakage of the internal fluid at a mechanical joint. With the exception of borated water leaks, there are no aging effects requiring management associated with external leakage of a mechanical joint. Loss of mechanical closure integrity resulting from borated water leaks is addressed in the LRA as discussed below.

When external leakage involves borated water, the aging effect of concern is loss of material due to aggressive chemical attack (i.e., boric acid corrosion of carbon or low alloy steel bolting). Therefore, the LRA addresses loss of mechanical closure integrity resulting from the external environment of "borated water leaks" and credits the Boric Acid Wastage Surveillance Program for management of this aging effect.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

The analysis of possible aging effects for reinforced concrete components in the Containments and Other Structures are summarized in the LRA Sections 3.5.1.3 (page 3.5-9) and 3.5.2.3 (page 3.5-24). The analysis is based on concrete material properties, the applicable environments, and years of operating experience. The analysis concludes that concrete structures exposed to aggressive environments require aging management, and concrete structures not exposed to aggressive environments do not require aging management. However, based on specific direction from the NRC Staff, license renewal applicants are required to implement an aging management program to manage aging of concrete structures. FPL proposes to credit the Systems and Structures Monitoring Program for managing aging of the accessible reinforced concrete structures listed in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93).

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.

FPL Response

As noted in LRA Appendix C, Section 5.1 (page C-11), galvanized steel is not susceptible to general corrosion except where buried, submerged, or subject to wetting other than humidity, such as salt spray. A “wetted” outdoor environment is one in which standing water accumulates or significant salt spray is present. Both wetted and non-wetted galvanized structures were identified by review of plant operating experience and direct inspection of galvanized structures, and both types are identified in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93). Based on 25+ years of St. Lucie plant operating experience, non-wetted galvanized structures, as defined in LRA Appendix C, Section 5.1 (page C-11), do not require aging management.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

Fuel Transfer Tube Flexible Membranes

The fuel transfer tube flexible membranes provide a seal between each containment annulus and the outdoor environment where the fuel transfer tubes penetrate the shield buildings. These membranes serve as a ventilation boundary for Shield Building Ventilation. These flexible membranes are made of radiation resistant silicon rubber designed for the subject environment.

As discussed in LRA Section 4.5.2 (page 4.5-2), the fuel transfer tube penetrations are not subject to elevated temperatures. Therefore, significant movements due to temperature fluctuations that could result in misalignment and loss of seal are not credible. Consequently, aging management of the seals is not required.

Lubrite Plates

Lubrite is the trade name for a low friction lubricant material used in applications where relative motion (sliding) is desired. At St. Lucie, the intended function of the lubrite plates is to facilitate relative motion (sliding) during RCS heat-up and cool-down.

Lubrite plates are provided on the steam generator upper supports (Elev. 76.00’) and on the sliding base supports (Elev. 23.25’) as well as at the reactor vessel nozzle supports to accommodate any operational movement. The external operating environment of the steam generator and the reactor vessel supports is containment air as described in LRA Table 3.0-2 (page 3.0-3).

In general, the operating temperature of the reactor vessel and steam generator supports is less than 450°F. The humidity inside containment averages 73%. The 60-year fluence at the reactor vessel supports (which bounds the 60-year fluence for the steam generator supports) is less than 6.15×10^{18} n/cm^2. Reactor coolant supports are designed for a wide variety of load combinations. The load values are depicted on plant drawings, which are available on-site.

The steam generator and reactor vessel supports are not normally exposed to borated water leaks. However, if a leak were to occur, the leak would be identified under the Boric Acid Wastage Surveillance Program.

As described in literature provided by Lubrite Technologies (formerly Merriman), Lubrite products are solid, permanent, completely self-lubricating, and require no maintenance. The Lubrite proprietary lubricant is a custom compound mixture of metals, metal oxides, minerals, and other lubricating materials combined with a lubricating binder. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed.

FPL performed an extensive search of industry and plant specific operating experience utilizing various sources, including the INPO website. No reported instances of Lubrite plate degradation or failure to perform their intended function were identified. Consequently, there are no known aging effects that would lead to a loss of intended function.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

Mechanical Penetration Seals

Some industry analysts have postulated increased hardness and shrinkage as potential aging effects for fire barrier penetration seals. However, based on the information provided in SECY-96-146 and St. Lucie plant operating experience, these theoretical aging effects are not applicable at St. Lucie.

SECY-96-146 “Technical Assessment of Fire Barrier Penetration Seals in Nuclear Power Plants” states that normal shrinkage does not have a significant impact on the function of silicone foam or elastomer as a fire barrier.

Excerpt from SECY-96-146:

5.10 Aging and Shrinkage

> "In its letter report entitled "Aging of Fire Barriers in Nuclear Power Plants," September 30, 1994, SNL reported that many fire barrier materials are resistant to thermally accelerated aging and that the material properties of silicone-based materials, which dominate the industry, are particularly age independent. SNL concluded that these materials are not expected to exhibit problems as they age. Moreover, on the basis of its review of operating experience and the technical literature, SNL did not find any penetration seal problems that were directly related to aging. SNL reported that it did not find information on thermal aging or radiation testing of grout, cement, and gel-type seals. SNL did not recommend an experimental aging program."

Based on information provided in SECY-96-146 and St. Lucie plant operating experience, fire barrier penetration seals do not experience aging effects that would lead to a loss of intended function.
This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

Fire Sealed Isolation Joint Carbon Steel Plates

A carbon steel closure plate is provided on both sides of the fire sealed isolation joint. The closure plates prevent mechanical damage of the fire rated materials (Cerablanket, Dymeric sealant, and Ethafoam) but is not relied upon for fire resistance. Therefore, loss of material for the closure plates will not cause a loss of intended function for the fire sealed isolation joint. Consequently, there are no aging effects requiring management for the closure plates. The closure plates were included in the material listing for the fire sealed isolation joint in LRA Table 3.5-8 (page 3.5-61) for completeness.

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.

FPL Response

The indoor − air conditioned environment is defined in LRA Table 3.0-2 (page 3.0-3) and discussed in LRA Appendix C, Section 4.2.3 (page C-9). Loss of material is not considered to be applicable for carbon steel components located in an indoor - air conditioned environment because the controlled atmosphere provided by air conditioning inhibits aging effects. This conclusion is based on years of plant and industry operating experience. Thus, there are no aging effects requiring management for carbon steel components in an indoor - air conditioned environment. Consequently, no aging management program is required.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

As described in LRA Section 2.4.2.9 (page 2.4-12), the emergency cooling canal and the portion of intake canal between the emergency cooling canal and the intake structures are in the scope of license renewal. Erosion of the associated earthen canal dikes is prevented by concrete erosion protection installed on the dike embankments. Aging of the concrete erosion protection is performed by the Systems and Structures Monitoring Program. Therefore, because the concrete erosion protection prevents aging of the earthen dikes, aging management of the earthen dikes is not required.

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?

FPL Response

The fuel transfer tube expansion bellows in a containment air environment listed in LRA Table 3.5-2 (page 3.5-38) are structural bellows that are not exposed to process fluid (i.e., borated refueling water). As indicated in LRA Section 4.5.2 (page 4.5-2), the fuel transfer tube penetrations are not subject to elevated temperatures and therefore are not subject to thermal fatigue. Consequently, there are no aging effects requiring management for fuel transfer tube expansion bellows in a containment air environment.

The fuel transfer tube expansion bellows are included in the St. Lucie containment leak rate testing program.

<u>RAI 3.5 - 7</u>

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.

<u>FPL Response</u>

As noted in the NRC summary of the May 15 and 16, 2002 meeting with FPL, dated June 21, 2002, this topic will be reviewed by the NRC during the Region II AMR inspection for St. Lucie.

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.

FPL Response

Inspection of the accessible portions of the sheet piling revealed no significant loss of material. The below groundwater portions of the sheet piling are not accessible. However, since bare steel within the submerged and subsoil zones has corrosion rates that are similar to, or lower than, corrosion rates for atmospheric conditions, the underground portions of the sheet piling are also considered to be in similar condition.

The impressed current cathodic protection systems that protect the discharge canal nose sheet piling and the ultimate heat sink dam sheet piling do not protect any other items. There are additional impressed current cathodic protection systems for other components and structures (e.g., barge slip, condenser water boxes, turbine cooling water heat exchangers, etc.). Based on plant specific operating experience, these systems have proven to be effective in providing corrosion protection.

RAI 3.5 - 9

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

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

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

existing condition of concrete structural members exposed to groundwater

FPL Response

The levels of contaminants (chloride and sulfates) and the pH level can be found in St. Lucie Unit 1 UFSAR Table 2.4-3 (page 2.4-53). Note that these values also apply St. Lucie Unit 2.

The grade elevation (+18') and the groundwater elevation (+2') are discussed in St. Lucie Unit 1 UFSAR Section 2.5.4.11 (page 2.5-65). Fluctuations in the groundwater are influenced by tidal changes in the Atlantic Ocean to the east, moderated by the Indian River to the west. Note that these values also apply St. Lucie Unit 2.

The Intake Structures have experienced concrete degradation that warranted corrective actions. Other concrete structures located below groundwater have not exhibited any indications of concrete degradation.

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.

FPL Response

Structural components in inaccessible areas are managed by visually examining structural components in accessible areas of in-scope structures and other relevant structures for conditions that could indicate the presence of degradation in such inaccessible areas. There are no known inaccessible structural components at St. Lucie, which do not have matching accessible components with the same material and environment. Structural components are exposed to the environments indicated in LRA Table 3.0-2, (page 3.0-3.)

For inaccessible concrete components, such as the exterior surfaces of below groundwater concrete structures, accessible interior surfaces of below groundwater concrete will be monitored for signs of degradation by visual inspection under the Systems and Structures Monitoring Program. In addition, consistent with page II A2-8 of the GALL report (LRA Reference 3.1-1), examination of representative samples of below groundwater concrete, when excavated for any reason, will be performed as part of the Systems and Structures Monitoring Program credited for managing aging of these structures.

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.

FPL Response

There is a typographical error in the final statement of LRA Section 3.5.2.4.2 (page 3.5-30). The word "not" was inadvertently omitted. The final statement should be "Based on the above, cracking is not an aging effect requiring management for miscellaneous structural components." LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93) correctly indicate that cracking is not an aging effect requiring management for miscellaneous structural components.

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.

FPL Response

Cracking of unreinforced masonry block walls is an aging effect requiring management, as indicated in LRA Section 3.5.2.3.2 (page 3.5-26), Table 3.5-9 (page 3.5-68), and Table 3.5−12 (page 3.5-80).

Cracking of reinforced masonry block walls is not an aging effect requiring management, since the reinforcing steel effectively controls cracking thus preventing a loss of intended function. During IE Bulletin 80-11 walkdowns, no significant cracking was identified. Furthermore, after many years of service, reinforced masonry block walls at St. Lucie have not exhibited cracking that could lead to a loss of intended function. For that reason, cracking of reinforced masonry block walls is not an aging effect requiring management.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

Based on the original St. Lucie cable routing design, plant specific operating experience, and periodic walkdowns that have been performed, there are no adverse localized environments caused by heat, radiation, or moisture present in areas where non-EQ cables and connections are located.

As indicated in LRA Subsection 3.6.2.2 (page 3.6-9), FPL performed an extensive review of St. Lucie Plant operating experience associated with cables and connections (connectors, splices, and terminal blocks), in part, to determine the existence of adverse localized environments. This review did not identify any adverse localized environments caused by heat, radiation, or moisture that might be detrimental to cables and connections. Occurrences of degraded cable are identified and dispositioned routinely through the corrective action and maintenance programs.

As indicated in LRA Subsection 3.6.1.1.6 (page 3.6-6), the potential sources of adverse localized heat environments at St. Lucie Units 1 and 2 are from high temperature Reactor Coolant, Main Steam, Feedwater and Blowdown System piping and components. Most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environments. The Reactor Auxiliary Buildings do not contain any high temperature Reactor Coolant, Main Steam, and Feedwater System piping and components. Although, the Reactor Auxiliary Buildings contain Blowdown System piping and components, the piping runs are limited to the mechanical penetration areas, and are not located near electrical cables and connections. With regard to radiation, the only buildings with any appreciable radiation levels are Containments, the Reactor Auxiliary Buildings and the Fuel Handling Buildings. However, non-EQ cables and connections in the Reactor Auxiliary Buildings and the Fuel Handling Buildings are not located in areas which would be subject to adverse localized radiation environments during plant operation, including those postulated based on the conservative assumption of 1% failed fuel (see further discussion below).

As stated in LRA Subsections 3.6.1.1.4 and 3.6.1.1.5 (pages 3.6-4 and 3.6-5) and summarized in LRA Tables 3.6-3 and 3.6-4 (pages 3.6-14 and 3.6-15), the evaluation of non-EQ cables and connections determined that each cable/connection type was capable of performing its function for the entire plant life, including the renewal term, assuming continuous exposure to design temperature and radiation conditions. Considering the conservatism (exposure to continuous design conditions) of these evaluations, the monitoring activities described in LRA Subsection 3.6.1.1.6 (pages 3.6-6 through 3.6-8) would ensure temperature and radiation conditions adverse to quality would be readily identified.

As discussed in Subsections LRA Subsections 3.6.1.1.1 (page 3.6-2) and 3.6.1.1.3 (pages 3.6-3 and 3.6-4), aging effects related to moisture for low voltage connectors and medium voltage cables do not require aging management at St. Lucie. All low voltage metal connections are located in enclosures or protected from the environment with qualified splices. St. Lucie Units 1 and 2 medium voltage applications, defined as 2kV to 15kV, use lead sheath cable to prevent the effects of moisture on the cables.

Due to the absence of adverse localized environments caused by heat, radiation, or moisture in areas where non-EQ cables and connections are present, inspection of these non-EQ cables and connections would be of little value. However, based on discussions with the NRC and in order to provide reasonable assurance that the intended functions of non-EQ cables and connections exposed to postulated adverse localized environments caused by heat or radiation will be maintained consistent with the current licensing basis through the period of extended operation, FPL proposes an aging management program for non-EQ cables and connections in the St. Lucie Containments. The non-EQ cables and connections managed by this program include those used for power and instrumentation and control that are within the scope of license renewal. The program attributes are discussed below.

Scope –

This inspection program includes accessible non-EQ cables, and connections within the scope of license renewal in the Containment structures at St. Lucie that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service condition for the electrical cable, or connection.

Preventive Actions –

No actions are taken as part of this program to prevent or mitigate aging degradation.

Parameters Monitored or Inspected –

Accessible non-EQ cables and connections within the scope of license renewal in the Containment structures installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, or surface contamination.

Detection of Aging Effects –

Cable and connection jacket surface anomalies are precursor indications of conductor insulation aging degradation from heat or radiation in the presence of oxygen and may indicate the existence of an adverse localized equipment environment. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service condition for the electrical cable, or connection. Accessible non-EQ cables and connections within the scope of license renewal in the Containment structures installed in adverse localized environments are visually inspected at least once every 10 years, which is an adequate period to preclude failures of the conductor insulation. The first inspection will be performed before the end of the initial 40-year license term. EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments," will be used as guidance in performing the inspections.

Monitoring and Trending –

Trending actions are not included as part of this program because the ability to trend inspection results is limited.

Acceptance Criteria –

No unacceptable visual indications of cable and connection jacket surface anomalies, which suggest that conductor insulation degradation exists, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

Corrective Actions –

Further investigation is performed through the corrective action program on non-EQ cables, and connections when the acceptance criteria are not met in order to ensure that the intended functions will be maintained consistent with the current licensing basis. When an adverse localized environment is identified for a cable or connection, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. Corrective actions may include, but are not limited to testing, shielding or otherwise changing the environment, relocation or replacement of the affected cable or connection. Corrective actions implemented as part of the corrective action program are performed in accordance with FPL's 10 CFR 50, Appendix B Quality Assurance Program.

Confirmation Process –

The confirmation process implemented as part of the corrective action program is performed in accordance with FPL's 10 CFR 50, Appendix B Quality Assurance Program.

Administrative Controls –

Administrative controls associated with this program will be performed in accordance with FPL's 10 CFR 50, Appendix B Quality Assurance Program.

Operating Experience –

Operating experience has not identified the presence of adverse localized heat and radiation environments in the Containments at St. Lucie. However, operating experience identified by NRC in the GALL Report has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes such as feedwater lines.

The program described above for the St. Lucie Containments is consistent with the program accepted by the NRC in the GALL Report. Accordingly, this program is an acceptable aging management program for non-EQ cables and connections within the scope of license renewal exposed to adverse localized equipment environments due to heat and radiation in the St. Lucie Containments. A description of this program will be added to the UFSAR Supplement in LRA Appendix A.

This aging management program is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

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.

FPL Response

The aging management reviews performed by FPL on non-EQ cables and connections determined that there were no aging effects that require management for the extended period of operation. These reviews included an assessment of aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits. A review of plant-specific operating experience performed as part of these aging management reviews (see LRA Subsection 3.6.2.2, page 3.6-9), which included a review of instrument calibration results and discussions with St. Lucie plant maintenance and engineering personnel, indicated that no failures of cables and connections associated with sensitive, low-level signal circuits have occurred due to aging.

However, as noted in the response to RAI 3.6.1.1-1, FPL has proposed an aging management program for non-EQ cables and connections in the St Lucie Containments to address postulated adverse localized environments caused by heat or radiation. An additional aging management program to address aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits is not considered necessary for the following reasons:

As noted above, the aging management reviews performed determined there were no aging effects requiring management.

26 and 19 years of operating experience at St. Lucie Units 1 and 2, respectively, have not identified the need for an aging management program tailored for non-EQ cables and connections associated with sensitive, low-level signal circuits.

The proposed program described in the response to RAI 3.6.1.1-1 which utilizes visual inspections will appropriately manage aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits.

A review of other license renewal Safety Evaluation Reports (SERs) indicates acceptance of visual inspections for managing aging of cables and connections. In addition, the Electrical Cable and Terminations Aging Management Guideline, SAND96-0344 (LRA Reference 3.6-1), concludes in Section 1.4 that "... reliance on visual inspection techniques for the assessment of low-voltage cable and termination aging appears warranted since these techniques are effective at identifying degraded cables."

The St. Lucie Non-EQ Cable and Connection Aging Management Program, as described in response to RAI 3.6.1.1-1, is consistent with GALL Report program XI.E1 and will provide reasonable assurance through visual inspection that instrument cables that are sensitive to reduced insulation resistance will maintain their intended functions during the period of extended operation. Accordingly, no additional aging management program is required.