ST. LUCIE UNITS 1 AND 2
DOCKET NOS. 50-335 AND 50-389
ATTACHMENT 1
SUPPLEMENTAL RESPONSE TO NRC REQUESTS FOR ADDITIONAL INFORMATION FOR REVIEW OF THE ST. LUCIE UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

RAI 2.2-2

Table 2.2-1 of the LRA does not include miscellaneous drains. On the basis of the plant internal flood analysis, documented in the Unit 1 and 2 Updated Final Safety Analysis Reports (UFSARs), it appears that the drain systems for many of the in-scope structures provide a flood protection barrier that supports the capability to shut down the reactor and maintain it in a safe shutdown condition. Degradation of these systems, such as blockage due to foreign material concentration or excessive corrosion, could invalidate the flooding analysis and prevent satisfactory accomplishment of the intended function of safety-related systems. Therefore, major portions of the plant/building drain system should be within the scope of license renewal and subject to an aging management review (AMR) per 10 CFR 54.4(a)(ii).

Examples of flooding analyses for Unit 2, which take credit for floor drains include:

- Break in the diesel generator building, page 3.6F-7.
- Break in the component cooling water building, page 3.6F-7.

Justify why these drain systems are considered to be outside the scope of license renewal or are not subject to an AMR.

FPL Response

The response below supercedes the response to RAI 2.2-2 transmitted in FPL Letter L-2002-144 dated October 3, 2002. This response is being revised to clarify that all Reactor Auxiliary Building and Fuel Handling Building drains credited in the flooding analyses are included in the scope of license renewal.

The system designated Miscellaneous Drains in LRA Table 2.2-1 (page 2.2-3) is associated with Extraction Steam which is not within the scope of license renewal as stated in LRA Section 3.4 (page 3.4-1). The scoping of drains for license renewal (as they relate to the St. Lucie Units 1 and 2 UFSAR flooding analyses) is discussed below.

Units 1 and 2 Reactor Auxiliary Buildings and Fuel Handling Buildings

All drains for these buildings credited in the flooding analyses are included in the scope of license renewal and identified in LRA Table 3.3-16 (page 3.3-89) as part of Waste Management.

Unit 1 Emergency Diesel Generator Building, Unit 1 Component Cooling Water Area, Units 1 and 2 Diesel Oil Equipment Enclosures, and Units 1 and 2 Intake Structures

The Units 1 and 2 UFSARs do not credit drains in the internal flooding analyses for these structures.

Unit 2 Emergency Diesel Generator Building

For the Unit 2 Emergency Diesel Generator Building, the internal flooding event (see Unit 2 UFSAR Section 3.6F.2.2.1(e), page 3.6F-6a) evaluated is an assumed crack in non safety-related service water piping resulting in an 18 gpm leak. This UFSAR evaluation indicates that the entire flow from the crack would drain through the drainage system from the Emergency Diesel Generator Building. However, assuming no credit for the drain piping (i.e., complete blockage), the ultimate elevation of water accumulation in the Unit 2 Emergency Diesel Generator Building for this event would only reach several inches above floor level, at which point the water would begin draining under the two doorways in each room of the building. Drainage capacity under these doorways would be more than adequate to accommodate the 18 gpm leak rate from the cracked service water line. The flooding elevation reached is well below the elevation of safety-related components, and therefore would not affect safety-related functions. Accordingly, the Unit 2 Emergency Diesel Generator drains do not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a), and thus are not within the scope of license renewal.

Unit 2 Component Cooling Water Area

For the Unit 2 Component Cooling Water Area, the internal flooding event (see Unit 2 UFSAR Section 3.6F.2.2.1(h), pages 3.6F-7 to 3.6F-8) evaluated is an assumed crack in safety-related intake cooling water piping resulting in a 490 gpm leak. Additionally, as noted in this UFSAR section, operator action to isolate the leak is assumed to occur 30 minutes after the pipe failure. Assuming no credit for the drain piping (i.e., complete blockage), the ultimate elevation of water accumulation in the Unit 2 Component Cooling Water Area for this event would be well below the elevation of safety-related components, and therefore would not affect safety-related functions. Accordingly, the Unit 2 Component Cooling Water Area drains do not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a), and thus are not within the scope of license renewal.

RAI 2.3.2 - 6

Figure 6.2-46 of the UFSARs for Units 1 and 2 shows gravity dampers (at numerous locations) as components of the containment cooling system. The housings for these components were neither identified in LRA Table 3.2-1 nor shown on License Renewal Boundary Drawings 1-HVAC-01 and 2-HVAC-01. It appears that these component housings are passive and long-lived and, as such, should be within the scope of license renewal and subject to an AMR. Justify why the gravity dampers are considered to be outside the scope of license renewal are not subject to an AMR.

FPL Response

The response below supercedes the response to RAI 2.3.2-6 transmitted in FPL Letter L-2002-144 dated October 3, 2002. This response is being revised to include an aging management review for the Containment Cooling damper housings in the scope of license renewal.

Containment cooling gravity dampers were considered to be within the scope of license renewal because they support Containment Cooling system intended functions. Gravity dampers do not appear in LRA Table 3.2-1 (page 3.2-9) because they were considered to be active components, and thus not subject to an aging management review in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. However, based upon the NRC staff's position on previous license renewal applications and expectations conveyed at meetings with the staff, aging management reviews of the gravity damper housings for Containment Cooling have been performed. LRA Table 3.2-1 is revised to include the following:

LRA page 3.2-10 (Internal Environment)
LRA page 3.2-13 (External Environment)

TABLE 3.2-1
CONTAINMENT COOLING

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Damper housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
External Environment					
Damper housings	Pressure boundary	Carbon steel	Containment air	Loss of material	Periodic Surveillance and Preventive Maintenance Program

For the above dampers, existing preventive maintenance activities will include inspection of both internal and external surfaces of the damper housings.

<u>RAI 2.3.3 - 15</u>

The license renewal rule, 10 CFR 50.54(a)(3), requires an applicant to include those structures, systems, and components (SSCs) that are relied on in a safety analysis or plant evaluation to perform a function which demonstrates compliance with 10 CFR 50.48, "Fire protection," to be included within the scope of the license. In general, operating licenses contain a license condition for fire protection that defines the 10 CFR 50.48 fire protection program. The license condition states that the licensee "shall implement and maintain in effect the provisions of the approved fire protection program" as described in the UFSAR and/or as approved in a safety analysis.

Comparing the applicable information contained in the LRA with the UFSAR, the staff identified SSCs in the UFSAR that were not included within the scope of license renewal. A sampling review by staff has identified the hydropneumatic tank and appurtenances (provides pressure maintenance for fire water system), and nitrogen tank for gaseous suppression system (pilot pressure for system actuation) that are included in the safety analysis, yet were not identified to be within the scope of license renewal.

Clarify the current licencing basis, consistent with 10 CFR 50.48, with respect to scoping for license renewal. Using the examples above, justify why SSCs listed in the UFSAR are considered to be outside the scope of license renewal.

<u>FPL Response</u>

The response below supercedes the response to RAI 2.3.3-15 transmitted in FPL Letter L-2002-144 dated October 3, 2002. This response is being revised to include the hydropneumatic tank in the scope of license renewal.

FPL's methodology for scoping pursuant to 10 CFR 54.4(a)(3) for fire protection for St. Lucie Units 1 and 2 is described in LRA Subsection 2.1.1.4.1 (page 2.1-7). This methodology calls for a review of the Current Licensing Bases (CLB) and other design documents down to the component level, and is the same as that utilized for Turkey Point Units 3 and 4 license renewal. This methodology has undergone two NRC scoping and screening audits as part of the Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2 license renewal reviews with no issues identified. Additionally, the NRC regional scoping and screening inspection for Turkey Point Units 3 and 4 did not identify issues related to fire protection scoping. Finally, the NRC Region II inspection team reviewed the adequacy of fire protection scoping and screening during the recently completed scoping and screening inspection at St. Lucie Units 1 and 2, and no issues were identified. Based on the above, FPL is confident that all SSCs relied on in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.48 have been identified as within the scope of license renewal. In a few cases, there are fire protection SSCs described in the St. Lucie Units 1 and 2 UFSARs that are not within the scope of license renewal. In these cases, the SSCs are not relied on to demonstrate compliance with 10 CFR 50.48, but are described in the UFSAR typically for information purposes only.

Further discussion for the two specific examples in RAI 2.3.3–15 are provided below.

Hydropneumatic Tank

As stated in St. Lucie Unit 1 UFSAR Section 9.2.6.2 and Unit 2 UFSAR Section 9.2.4.2, the hydropneumatic tank is part of Potable and Sanitary Water (includes Service Water). As stated in both UFSARs, these systems serve no safety function since neither is required to achieve safe shutdown nor to mitigate the consequences of a design basis accident. Unit 1 UFSAR, Appendix 9.5A, makes the following statements with regard to the hydropneumatic tank:

Page 9.5A-46

"The entire fire suppression water supply system is maintained under pressure in the range of 95 to 125 psig by means of a hydropneumatic tank, pressurized by domestic water pumps. The fire pumps are designed for automatic starting when the fire main pressure drops to greater than or equal to 85 psig."

Page 9.5A-109

"The use of the hydropneumatic tank for small makeup and the maintenance of a system pressure helps prevent frequent starting of the motor driven pump."

"The fire water system, when not operating, is kept pressurized by a hydropneumatic tank. This tank pressure is maintained in the range of 95 to 125 psig by the domestic water pumps. If a manual or automatic water fire suppression system is actuated causing fire water system pressure to decrease both fire pumps start automatically when the header pressure drops to greater than or equal to 85 psig."

"A timing device for sequential pump starts is not installed in accordance with NFPA-20, but the intent of NFPA-20 is met with the alternate configuration which incorporates a hydropneumatic tank to keep the system full of water to prevent water hammer, and is powered by separate electrical busses to prevent system electrical overload."

Page 9.5A-114

"The sizing of the domestic water pumps and hydropneumatic tank is designed to keep the fire loop pressurized between 95 and 125 psig during normal operation."

Similar statements are made in the Unit 2 UFSAR on pages 9.5A-45, 9.5A-105, and 9.5A-106.

The hydropneumatic tank was determined not to be in the scope of license renewal for the following reasons.

1. Although the hydropneumatic tank normally maintains pressure on the fire main, it is isolated by a check valve upon start of the fire pumps. Thus, the tank is not in service when Fire Protection is performing its system intended functions.
2. If the hydropneumatic tank were assumed not to be in service during normal operation, the fire pumps would start more frequently. This condition, although a maintenance consideration for the fire pumps, would not prevent Fire Protection from performing its system intended functions. Operability of the fire pumps is assured through periodic flow testing in accordance with the Fire Protection Program. There is no requirement in the Units 1 and 2 UFSARs for a pressure maintenance system to satisfy fire protection requirements.

3. The statements with regard to NFPA-20 are related to requirements for automatic controls associated with sequential start of the fire pumps. The hydropneumatic tank is not credited in satisfying these NFPA-20 requirements, because the fire pumps will start when the fire main pressure drops to greater than or equal to 85 psig regardless of the condition of the hydropneumatic tank. St. Lucie Unit 1 (includes fire water supplies for both units) was designed to the 1972 version of NFPA-20, which does not require a pressure maintenance system.
4. The hydropneumatic tank is not included in the "fire protection plan" as defined in 10 CFR 50.48.

Based on the above, the hydropneumatic tank does not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a), and thus is not within the scope of license renewal.

However, based upon the NRC reviewer's position and expectations conveyed at several meetings with the NRC, the hydropneumatic tank and a portion of Service Water required for pressure maintenance of the fire water system are added to the scope of license renewal. This includes the following:

1. Hydropneumatic tank and associated instrumentation, vents, drains, and other pressure boundary appurtenances
2. Domestic water pumps, suction lines from the city water storage tanks, and discharge lines to the hydropneumatic tank (Note: also includes pump recirculation lines up to orifices SO-15-4A and SO-15-4B)
3. The main service water header from the hydropneumatic tank to the fire water system check valve V15243 and its branch connections up to Valves V15237, PCV-15-11, V15186, and V15235

Although some of the boundaries established by the above components are not closed valves, these boundaries are considered acceptable for license renewal based upon continuous pressure monitoring of the system. The hydropneumatic tank contains a low pressure switch which initiates an alarm in the Control Room and at a local water treatment annunciator panel. Additionally, as part of the normal shift operator rounds, plant operators check the hydropneumatic tank and domestic water pumps for abnormal conditions in accordance with the operations department operating instructions. Therefore, any significant reduction in system pressure will be immediately detected and corrective actions initiated.

Table 3.3-6 is modified as follows:

LRA page 3.3-42 (Internal Environment)
LRA page 3.3-45 (External Environment)

TABLE 3.3-6
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Hydropneumatic tank	Pressure boundary	Carbon steel	Air/gas [1] Raw water – city water	Loss of material	Periodic Surveillance and Preventative Maintenance Program[2]
Domestic water pumps	Pressure boundary	Carbon steel	Raw water – city water	Loss of material	Periodic Surveillance and Preventative Maintenance Program[2]
Site glasses	Pressure boundary	Glass	Air/gas	None	None Required
		Carbon steel	Raw water – city water	Loss of material	Periodic Surveillance and Preventative Maintenance Program[2]
Piping/fittings	Pressure boundary	Galvanized carbon steel	Raw water – city water	Loss of material	Periodic Surveillance and Preventative Maintenance Program[2]
External Environment					
Hydropneumatic tank	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Domestic water pumps	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Site glasses	Pressure boundary	Glass	Outdoor	None	None Required
		Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Piping/fittings	Pressure boundary	Galvanized carbon steel	Outdoor	None	None required

NOTES

1. Potentially humid air due to water in lower portion of the tank.
2. Pressure monitoring.

Nitrogen Tank

Unit 1 UFSAR Chapter 9.5A, Section 3.1.3, Page 9.5A-117 describes the nitrogen tank, as a small, vendor-supplied cartridge. This cartridge is in the scope of license renewal, and was inadvertently omitted from Table 3.3-6. Table 3.3-6 is modified as follows:

LRA page 3.3-42 (Internal Environment)
LRA page 3.3-45 (External Environment)

TABLE 3.3-6
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program Activity
Internal Environment					
Unit 1 Halon nitrogen tank [VII.I.1.1]	Pressure boundary	Carbon steel	Air/gas	None	None required
External Environment					
Unit 1 Halon nitrogen tank [VII.I.1.1]	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Fire Protection Program

RAI 2.3.3.15 - 1

The ventilation system license renewal boundary drawings, which are identified below, show damper components for both Units 1 and 2; however, LRA Table 3.3-15 does not identify the housings for these dampers. It appears that these component housings are passive and long-lived and, as such, should be within the scope of license renewal and subject to an AMR. Justify why these components are considered to be outside the scope of license renewal or are not subject to an AMR.

NOTE: Numbers added by FPL to correlate response to specific question.

- Unit 1 on license renewal boundary drawing 1-HVAC-01, Rev. 0
  1. Hot shutdown panel housing for fans HVS-9 and HVE-35 at locations E7 and D7
  2. Unlabeled damper housing at locations E7
- Unit 1 on license renewal boundary drawing 1-HVAC-02, Rev. 0
  1. Control room cooling system damper housings D-17 at location B5, D-18 at location B6, D-19 at location C6, GD-5 at location B6, GD-6 at location C6, D-20 at location A7, D-21 at location B7, D-22 at location C7, GD-7 at location A8, GD-8 at location B8, GD-9 at location C8, D-29A at location C4, D-29B at location C5, D-41 at location C8, D-42 at location C7, and unlabeled at locations C8 and D8
  2. Control room cooling system fan housings HVE-13A at location B6; HVE-13B at location C6; HVA-3A, 3B, and 3C at locations A7, B7, and C7, respectively; HVA-10A at location C8; and 10B at location D8
  3. Control room cooling system charcoal adsorber housings for heating, ventilation and air conditioning (HVAC) units HVE-13A and 13B at location B5
  4. Emergency core cooling system area ventilation fan housings HVS-4A and 4B at locations D2 and E2, and HVE-9A and 9B at locations D5 and E5
  5. Emergency core cooling system area ventilation damper housings L-8 at location E1; GD-3 at location D2; GD-4 at location E2; D-1, D-2, D-3, and D-4 at location D3; D-8A and D-8B at location E3; GD-12 at location E3; D-7A and D-7B at location F3; D-9A and D-9B at location D4; D-12A and D-12B at location E4; D-5A and D-5B at location E4; D-6A and D-6B at location F4; D-13 and D-14 at location D4; D-15 and D-16 at location E4; L-7A at location D5; and L-7B at location E5
  6. Housings for battery room exhaust fans RV-1 and RV-2 at location G3, and an unlabeled gravity damper housing at location G3
  7. Housings for electrical equipment room fans HVS-5A and HVS-5B at locations G5 and H5, RV-3 and RV-4 at locations G5 and G6, and HVE-11and HVE-12 at locations G6 and H6
  8. Housings for electrical equipment room dampers L-11 at location G4, GD-1 and GD-2 at location G5, unlabeled dampers at locations G5 and G6, and L-9 and L-10 at locations G6 and H6
  9. Housings for shield building ventilation fans HVE-6A and 6B at locations D7 and F7
  10. Housings for shield building ventilation dampers GD-10 and D-23 at location D7, and GD-11 and D-24 at location F7

11. Housings for outdoor air conditioning units ACC-3A, ACC-3B, and ACC-3C at locations A7, B7, and C7
12. Housings for air handling units HVA-10A and HVA-10B at locations C8 and D8

- Unit 2 on license renewal boundary drawing 2-HVAC-01, Rev. 0
  1. Intake structure exhaust fan housings 2HVE-41A and 41B at location F5
  2. Housings for unlabeled intake structure pressure dampers at location F5

- Unit 2 on license renewal boundary drawing 2-HVAC-02, Rev. 0
  1. Control room cooling system damper housings D-17A at location A3; D-17B, D-20, D-21, and D-22 at location C3; D-18 at location A4; D-19 at location B4; GD-5 at location A4; GD-6 at location B4; unlabeled at locations A5, B5, and C5; GD-7 at location A6; GD-8 at location B6; GD-9 at location C6; DPR-25-2 at location A6; DPR-25-4 at location B6; DPR-25-3 at location C6; D39 at location C5; and D40 at location D5
  2. Control room cooling system fan housings 2HVE-13A at location A4 and 2HVE-13B at location B4
  3. Housings for air handling unit fans 2HVA/ACC-3A at location A6, 2HVA/ACC-3B at location B, and 2HVA/ACC-3C at location C6
  4. Control room cooling system charcoal adsorber housings for HVAC units 2HVE-13A and 13B at locations A4 and B4
  5. Emergency core cooling system area ventilation fan housings 2HVS-4A and 4B at locations D2 and E2, and 2HVE-9A and 9B at locations D5 and E5
  6. Emergency core cooling system area ventilation damper housings 2L-8 at location E1; unlabeled at locations D2 and E2; D-1, D-2, D-3, and D-4 at location D3; GD-12 at location E3; D-7B at location F3; unlabeled at location F3 (total of 3); D-9A and D-9B at location D4; D-12A and D-12B at location E4; D-13 at location D4; D-15 at location E4; D-14 at location D5; D-16 at location E5; 2L-7A at location D7; and 2L-7B at location E7
  7. Housings for battery room exhaust fans RV-1, RV-2, RV-3, and RV-4 at location H2, and unlabeled damper at location G2
  8. Housings for electrical equipment room fans 2HVS-5A and 5B at locations G3 and H3, and 2HVE-11 and 12 at location H4
  9. Housings for electrical equipment room dampers 2L-11 at location G3, GD-1 and GD-2 at locations G3 and H3, 2FDPR-25-123 and 2FDPR-25-119 at location G4, and GD-19 and GD-20 at locations G4 and H4

- Unit 2 on license renewal boundary drawing 2-HVAC-03, Rev 0
  1. Fuel handling building ventilation damper housings D-29 and D-30 at location B2, D-33 and D-34 at location C2, D-31 and D-32 at location B4, D-35 and D-36 at location C4
  2. Housings for shield building ventilation fans 2HVE-6A and 6B at locations D6 and F6
  3. Housings for shield building ventilation dampers GD-10 at location D6, D-23 at location D7, GD-11 at location F6, and D-24 at location F7

FPL Response

The response below supercedes the response to RAI 2.3.3.15-1 transmitted in FPL Letter L-2002-144 dated October 3, 2002. This response is being revised to address inconsistencies identified by the NRC regarding internal aging effects associated with carbon steel housings for fans and dampers.

As noted in LRA Subsection 2.1.2.1 (page 2.1-12), active/passive determinations were performed based on the guidance of Appendix B of NEI 95-10.

Consistent with that guidance, fans and dampers (including their housings) are defined as active components and thus do not require an AMR. However, based upon the NRC staff's position on previous license renewal applications and expectations conveyed at prior meetings with the staff, housings for fans and dampers have been included in the aging management review for the applicable ventilation systems. Changes to LRA Table 3.3-15 (pages 3.3-75 through 3.3-88), if required, as a result of the above are addressed in the specific responses below.

- License Renewal Boundary Drawing 1-HVAC-01

1. HVS 9 is included in Miscellaneous Ventilation in component grouping "Filter housings" and HVE-35 is included in Miscellaneous Ventilation in component grouping "Ducts" in LRA Table 3.3-15 (page 3.3-82).
2. Unlabeled damper at E7 is in Miscellaneous Ventilation. See Table 2.3.3.15-1-4 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."

- License Renewal Boundary Drawing 1-HVAC-02

1. Dampers D-17, D-18, D-19, GD-5, GD-6, D-20, D-21, D-22, GD-7, GD-8, GD-9,D-29A, D-29B, D-41, and D-42 are in Control Room Air Conditioning. See Table 2.3.3.15-1-1 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings." The unlabeled dampers at C8 and D8 are in Miscellaneous Ventilation. See Table 2.3.3.15-1-4 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
2. Fan housings HVE-13A and HVE-13B are in Control Room Air Conditioning. See Table 2.3.3.15-1-1 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings." Fan housings HVA-3A, HVA-3B, and HVA-3C are included in Control Room Air Conditioning in component grouping "Filter housings" in LRA Table 3.3-15 (pages 3.3-76 and 3.3-77). Fan housings HVA-10A and HVA-10B are included in Miscellaneous Ventilation in component grouping "Filter housings" in LRA Table 3.3-15 (page 3.3-82).
3. The control room air conditioning charcoal adsorbers are housed inside an air-handling unit (which also houses the filter), the fans housing is included in component grouping "Filter housings" in LRA Table 3.3-15, pages 3.3-76 and 3.3-77.
4. Fan housings HVS-4A and HVS-4B are included in Reactor Auxiliary Building (RAB) Main Supply and Exhaust in component grouping "Shell for HVS-4A and HVS-4B plenum and filters" in Table 3.3-15 (pages 3.3-85 and 3.3-86). Fan housings HVE-9A and HVE-9B are in Emergency Core Cooling System (ECCS) Area Ventilation. See Table 2.3.3.15-1-2 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."

5. Dampers L-8, GD-3, GD-4, D-1, D-2, D-3, D-4, D-8A, D-8B, GD-12, D-7A, D-7B, D-9A, D-9B, D-12A, D-12B, D-5A, D-5B, D-6A, and D-6B, are in RAB Main Supply and Exhaust. See Table 2.3.3.15-1-6 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings." Dampers D-13, D-14, D-15, and D-16, and L-7A and L-7B are in ECCS Area Ventilation. See Table 2.3.3.15-1-2 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
6. Fan housings RV-1 and RV-2 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings." Gravity Damper at location G3 is in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
7. Fan housings HVS-5A and HVS-5B are included in RAB Electrical and Battery Room Ventilation in component grouping "Shell for HVS-5A and HVS-5B plenum and filters" in Table 3.3-15 (pages 3.3-83 and 3.3-84). Fan housings RV-3, RV-4, HVE-11 and HVE-12 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."
8. Dampers L-9, L-10, and L-11 are mounted in the wall of the RAB, and thus do not have housings. Dampers GD-1, GD-2, and the unlabeled dampers at G-5 and G-6 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
9. Fan housings HVE-6A and HVE-6B are in Shield Building Ventilation. See Table 2.3.3.15-1-7 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."
10. Dampers GD-10, D-23, GD-11 and D-24 are in Shield Building Ventilation. See Table 2.3.3.15-1-7 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
11. The control room air conditioning outdoor air conditioning units ACC-3A, ACC-3B, and ACC-3C are active components, therefore they do not require an AMR.
12. Fan housings HVA-10A and HVA-10B are included in Miscellaneous Ventilation in component grouping "Filter housings" in LRA Table 3.3-15 (page 3.3-82).

- License Renewal Boundary Drawing 2-HVAC-01

1. Fans 2HVE-41A and 2HVE-41B are mounted in the roof of the intake cooling water pump enclosure, and thus do not have housings.
2. Dampers are mounted in the wall of the intake structure, and thus do not have housings.

- License Renewal Boundary Drawing 2-HVAC-02

1. Dampers D-17A, D-17B, D-20, D-21, D-22, D-18, D-19, GD-5, GD-6, GD-7, GD-8, GD-9, DPR-25-2, DPR-25-3, DPR-25-4, D-39, D-40, and unlabeled dampers at locations A5, B5, and C5 are in Control Room Air Conditioning. See Table 2.3.3.15-1-1 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
2. Fan housings 2HVE-13A and 2HVE-13B are in Control Room Air Conditioning. See Table 2.3.3.15-1-1 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."

3. Fan housings 2HVA/ACC-3A, 2HVA/ACC-3B, and 3HVA/ACC-3C are included in Control Room Air Conditioning in component grouping "Filter housings" in LRA Table 3.3-15 (pages 3.3-76 and 3.3-77).
4. The control room air conditioning charcoal adsorbers are housed inside an air-handling unit (which also houses the filter), the fans housing is included in component grouping "Filter housings" in LRA Table 3.3-15, pages 3.3-76 and 3.3-77.
5. Fan housings 2HVS-4A and 2HVS-4B are included in RAB Main Supply and Exhaust in component grouping "Shell for HVS-4A and HVS-4B plenum and filters" in Table 3.3-15 (pages 3.3-85 and 3.3-86). Fan housings 2HVE-9A and 2HVE-9B are in ECCS Area Ventilation. See Table 2.3.3.15-1-2 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."
6. Dampers 2L-8, D-1, D-2, D-3, D-4,GD-12, D-7B, D-9A, D-9B, D-12A, D-12B and the unlabeled dampers at locations D2, E2, and F3 are in RAB Main Supply and Exhaust. See Table 2.3.3.15-1-6 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings." Dampers D-13, D-14, D-15, and D-16, and 2L-7A and 2L-7B are in ECCS Area Ventilation. See Table 2.3.3.15-1-2 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
7. Fan housings RV-1, RV-2, RV-3 and RV-4 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings." The unlabeled damper at G-2 is in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
8. Fan housings 2HVS-5A, 2HVS- 5B, 2HVE-11, and 2HVE-12 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-1-5 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."
9. Damper 2L-11 is mounted in the wall of the RAB, and thus does not have a housing. Dampers GD-1, GD-2, 2FDPR-25-123, 2FDPR-25-119, GD-19, and GD-20 are in RAB Electrical and Battery Room Ventilation. See Table 2.3.3.15-5 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."

- License Renewal Boundary Drawing 2-HVAC-03

1. Dampers D-29, D-30, D-31, D-32, D-33, D-34, D-35, and D-36 are in Fuel Handling Building Ventilation. See Table 2.3.3.15-1-3 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."
2. Fan housings 2HVE-6A and 2HVE-6B are in Shield Building Ventilation. See Table 2.3.3.15-1-7 for changes to LRA Table 3.3-15 associated with component grouping "Fan housings."
3. Dampers GD-10, D-23, GD-11 and D-24 are in Shield Building Ventilation. See Table 2.3.3.15-1-7 for changes to LRA Table 3.3-15 associated with component grouping "Damper housings."

TABLE 2.3.3.15-1-1

LRA page 3.3-76 (Internal Environment)
LRA page 3.3-78 (External Environment)

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Control Room Air Conditioning					
Internal Environment					
Fan housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Carbon steel	Air/gas[1]	None	None required
		Galvanized carbon steel	Air/gas	None	None required
External Environment					
Fan housings	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housings	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Carbon steel	Indoor – air conditioned	None	None required
		Galvanized carbon steel	Indoor – not air conditioned	None	None required

NOTES:
1. Air conditioned air environment.

TABLE 2.3.3.15-1-2

LRA page 3.3-79 (Internal Environment)
LRA page 3.3-80 (External Environment)

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Emergency Core Cooling Systems Area Ventilation					
Internal Environment					
Fan housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housings	Pressure boundary	Galvanized carbon steel Aluminum	Air/gas	None	None required
		Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
External Environment					
Fan housings	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housings	Pressure boundary	Galvanized carbon steel Aluminum	Indoor – not air conditioned	None	None required
		Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program

TABLE 2.3.3.15-1-3

LRA page 3.3-81

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Handling Building Ventilation					
Internal Environment					
Damper housings	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
External Environment					
Damper housings	Pressure boundary	Galvanized carbon steel	Indoor – not air conditioned	None	None required

TABLE 2.3.3.15-1-4

LRA page 3.3-82

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Miscellaneous Ventilation					
Internal Environment					
Damper housings	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
External Environment					
Damper housings	Pressure boundary	Galvanized carbon steel	Indoor – not air conditioned	None	None required

TABLE 2.3.3.15-1-5

LRA page 3.3-83 (Internal Environment)
LRA page 3.3-84 (External Environment)

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Electrical and Battery Room Ventilation					
Internal Environment					
Fan housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Aluminum	Air/gas	None	None required
Damper housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel Aluminum	Air/gas	None	None required
External Environment					
Fan housings	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Aluminum	Outdoor	None	None required
Damper housings	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel Aluminum	Indoor – not air conditioned	None	None required

TABLE 2.3.3.15-1-6

LRA page 3.3-85 (Internal Environment)
LRA page 3.3-86 (External Environment)

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Main Supply and Exhaust					
Internal Environment					
Fan housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housing	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel	Air/gas	None	None required
External Environment					
Fan housings	Pressure boundary	Carbon steel[1]	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housing	Pressure boundary	Carbon steel[1]	Indoor – not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel	Indoor – not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

NOTES:
1. Not located near borated water sources.

TABLE 2.3.3.15-1-7

LRA page 3.3-87 (Internal Environment)
LRA page 3.3-88 (External Environment)

TABLE 3.3-15
VENTILATION

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Shield Building Ventilation					
Internal Environment					
Fan housings	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housing	Pressure boundary	Carbon steel	Air/gas	Loss of material	Systems and Structures Monitoring Program
		Carbon steel[1]	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel	Air/gas	None	None required
External Environment					
Fan housings	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Damper housing	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Systems and Structures Monitoring Program
		Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Galvanized carbon steel	Indoor – not air conditioned	None	None required

NOTES:
1. Damper D-24.

As identified in the tables above, both the Periodic Surveillance and Preventive Maintenance Program and the Systems and Structures Monitoring Program (LRA Appendix B Subsection 3.2.11 page B-46 and LRA Appendix B Subsection 3.2.14 page B-58, respectively) are credited for managing the aging effects associated with carbon steel damper housings. With the exception of Unit 1 Shield Building Ventilation, for those cases where the damper housing corresponds to a fan discharge damper (e.g., gravity discharge damper), the existing preventive maintenance activity for the fan will include inspection of both internal and external surfaces of the damper housing. However, for those dampers in Shield Building Ventilation with limited access, only external visual inspection of the housing will be credited. As identified in the Table 2.3.3.15-1-7 above, various Unit 1 damper housings (GD-10, GD-11, and D-23) credit the Systems and Structures Monitoring Program for managing the internal aging effect of loss of material. The Systems and Structures Monitoring Program is typically utilized for managing external aging effects since it employs periodic visual inspections of external surfaces for evidence of degradation. For these ventilation dampers the Systems and Structures Monitoring

Program is deemed to be adequate for managing internal loss of material due to general corrosion for the following reasons:

1. The ventilation dampers are located in indoor areas and their housings are internally coated, therefore, significant corrosion is not expected.
2. Twenty six years of operating experience has not identified that internal loss of material due to general corrosion has been a problem with these damper housings.
3. Any degradation of the internal coating with age could result in localized corrosion. If the corrosion was significant enough, the localized loss of material could result in a small perforation. This internal degradation would be evident by visible rust discoloration on the external surface of the damper housing. Should internal coating degradation and corrosion lead to small perforations, this condition would be well within ventilation system capacity and would not impact intended function.
4. Shield Building Ventilation is periodically tested to verify system capability.

Note that this approach is consistent with that accepted by the NRC as part of the Turkey Point LRA review for similar ventilation damper housings.

RAI 2.4.1 - 6

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.

FPL Response

The response below supercedes the response to RAI 2.4.1-6 transmitted in FPL Letter L-2002-144 dated October 3, 2002. This response is being revised to address impact energy of a fallen vent stack.

FPL did not include the St. Lucie Units 1 and 2 vent stacks in the scope of license renewal because they do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). However, the NRC has requested that FPL justify why the vent stacks are not in the scope of license renewal based on three specific reasons identified in RAI 2.4.1-6. FPL responses to these reasons are provided below.

(1) Structural failure of the vent stacks would not result in the failure of the Units 1 and 2 Containments and Reactor Auxiliary Buildings to perform their safety-related intended functions. If the vent stacks were assumed to fall, they could potentially impact the walls of the Containments, or the walls and/or roofs of the Reactor Auxiliary Buildings. These structures are constructed of cast in place, reinforced concrete with thickness ranging from 2 to 4 feet, and they are designed to resist high energy missiles without spalling (see Section 3.5 in the Unit 1 and Unit 2 UFSARs). These high-energy missiles bound the impact of a fallen vent stack.

    An analysis has been performed that demonstrates a structural failure of a plant vent stack is enveloped by the high-energy missiles described in the UFSARs. The 135' tall plant vent stack weighs approximately 64,000 lbs. The impact energy of the bounding critical case missile is approximately 155,000 ft-lbs. The incremental impact energy of a fallen vent stack ranges from 2 ft-lbs at the base to approximately 96,000 ft-lbs at the top. Additionally, with regard to impact of vent stack failure on the Unit 1 Control Room Air Conditioning condensing units, loss of all three units due to natural phenomenon (the only type of events that can cause failure of the vent stack), has been evaluated with acceptable results (see UFSAR Section 9.4.1.2).

(2) Although the vent stack radiation monitors are mentioned in Section 15.4.2.2 of the Unit 1 UFSAR, these monitors do not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). As stated in this UFSAR section, "Releases from the waste gas tank are exhausted by the auxiliary building main ventilation system through the plant vent. This exhaust is assumed to be released at ground level and to leak back into the auxiliary building." This UFSAR section also states, "It is conservatively assumed that the control room immediately receives in-leakage from the reactor auxiliary building." Finally, this section states, "The waste gas accident would result in a high radiation alarm from either local monitors or the stack vent." The local monitors mentioned in this statement are the ones located in Control Room Air Conditioning. As identified in Section 9.4.1 of the Unit 1 UFSAR, and Section 12.3.4.2.3.2 of the Unit 2 UFSAR, safety-related isolation of Control Room Air Conditioning is provided by redundant radiation monitors located in each of the Control Room Air Conditioning air intakes. As identified in Subsection 2.3.3.15 (page 2.3-25) of the LRA, the St. Lucie Units 1 and 2 Control Room Air Conditioning subsystems (and associated radiation monitors) are included in the scope of license renewal.

(3) As a conservative measure, FPL has included the supports for the vent stacks in the scope of license renewal as identified in Table 3.5-2 (page 3.5-42) of the LRA. This will ensure there are no credible structural failure modes of the vent stack (based on industry and plant specific operating experience) which would result in blockage of effluent flow.

Based on the above, the St. Lucie Units 1 and 2 vent stacks are not in the scope of license renewal.

RAI 3.3.2-3

The applicant did not identify SCC as an aging effect for the CCW heat exchanger tubes that are exposed to raw water. The operating experience at Turkey Point Station, shows that the CCW heat exchanger tubes, which are made of aluminum brass and exposed to raw water on the tube side, are susceptible to SCC (see U. S. Nuclear Regulatory Commission "Safety Evaluation Report with Open Items Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4," dated August 2001, p. 239). Provide the bases for excluding cracking as an applicable aging effect for CCW heat exchanger tubes that are exposed to raw water at St. Lucie.

FPL Response

The response below supercedes the response to RAI 3.3.2-3 transmitted in FPL Letter L-2002-159 dated September 26, 2002. This response is being revised to clarify that sacrificial anodes in the Component Cooling Water heat exchangers are not credited for license renewal.

The metallurgical analysis of the failed Turkey Point Component Cooling Water (CCW) heat exchanger tubes revealed that the cracking was initiated from the inside diameter (raw water side) and was located in the tube roll transition zone of the tube sheet. The cracking was determined to be transgranular stress corrosion cracking and was caused by the use of a new chemical injection system and the absence of sacrificial anodes. The tubes were replaced, the chemical injection system was removed from service, and zinc anodes were installed as an additional preventive measure.

Although the St. Lucie CCW heat exchangers also utilize aluminum brass tubes, they have not experienced stress corrosion cracking (SCC). This is primarily due to the fact that St. Lucie never utilized a chemical injection system similar to the one once installed at Turkey Point. Additionally, although not credited for aging management at St. Lucie, sacrificial anodes are installed as a preventive measure to protect the raw water side of the CCW heat exchangers. Finally, a review of St. Lucie metallurgical analysis reports of CCW heat exchanger tubes removed in 1988 and 1991 did not identify the presence of SCC. Therefore cracking due to SCC is not an aging affect requiring management for these components.

RAI 3.3.2-4

Aging effects for CCW system components exposed to the air/gas environment depend, in part, on the type of air/gas environment, the operating temperature, and the water content. Provide the characteristic parameters of the air/gas environments applicable to the components found in the CCW system. Also provide the bases for excluding corrosion as an applicable aging effect for CCW components that are exposed to the air/gas environment.

FPL Response

The response below supercedes the response to RAI 3.3.2-4 transmitted in FPL Letter L-2002-159 dated September 26, 2002. This response is being revised to describe the use of the MCIC report referenced in the response.

The Component Cooling Water (CCW) surge tanks are vented carbon steel tanks that are internally coated for corrosion protection. The air/gas internal environment identified in LRA Table 3.3-2 (pages 3.3-18 and 3.3-19) applies to the CCW surge tanks and associated valves, piping and fittings located above the normal tank water level. This air/gas environment constitutes the atmospheric air of the surroundings (i.e., "indoor – not air-conditioned"). See LRA Appendix C Subsection 4.1.3 (page C-8).

The aging management review of the internal surfaces of the carbon steel CCW surge tanks exposed to an air/gas environment identified general corrosion as a potential aging mechanism. Based upon the location of these tanks (i.e., inside the Reactor Auxiliary Building) and the limited air exchange with the environment provided by their 2" vents, aggressive chemical species will not be present and significant pitting corrosion is not expected. Additionally, these tanks are internally coated and a review of St. Lucie plant-specific operating experience did not identify corrosion as an aging effect requiring management.

A calculation was performed to demonstrate that the 80 mils design corrosion allowance for these tanks will accommodate any potential internal corrosion. Utilizing conservative corrosion rates for "Steel Category A" from Tables 6-1 and F-1 of MCIC Report, July, 1986, "Corrosion of Metals in Marine Environment" by J. A. Beavers, G. H. Koch and W. E. Berry, the worst case internal loss of material is calculated to be 76 mils. The corrosion rates are derived from Table 6-1 utilizing the "inland" environment and "Average Reduction in Thickness" data. As mentioned above, the aging mechanism of concern for the internal surfaces of the CCW surge tank air space is general corrosion. Therefore, uniform loss of material is expected and the column providing an average reduction in thickness is applicable. The "Inland" environment data is applicable based upon expected conditions for the air space inside the CCW surge tank. Since the CCW surge tank is located inside the Reactor Auxiliary Building and has a small vent providing for limited air exchange with surrounding environment, the high humidity of inland tropical environment without aggressive species, such as chlorides, is applicable. The corrosion rates utilizing this data are 2.8 mils for the first year, 2.3 mils for the second year (i.e., 5.1 cumulative), 3.2 mils for the third and fourth years (i.e. 8.3 cumulative), and approximately 1.1 for each of the next 4 years (i.e., 12.6 mils total for 8 years). For conservatism, a corrosion rate of 3 mils/year was assumed for the first 8 years, followed by a 1 mil/year corrosion rate for the remainder of plant life (3 mils/year x 8 years + 1 mil/year x 52 years). These corrosion rates are based upon comprehensive evaluations of corrosion damage to steel exposed to tropical atmosphere in the Panama Canal Zone. As expected, the corrosion rate decreases with time due to the buildup of an oxidation layer which will tend to provide some protection of the bare metal underneath. The use of these corrosion rates assumes no preventive measures (i.e., existing coatings) have been implemented since original installation, and thus incorporates inherent design margin. Based on these results, the minimum required design wall thickness of the tanks is maintained. Therefore, loss of material due to corrosion of the internal surfaces of the CCW surge tanks (which are exposed to an air/gas environment) is not an aging effect requiring management.

The aging management review of the internal surfaces of the small diameter carbon steel valves and schedule 80 pipe/fittings associated with the level switches/sight glasses of the CCW surge tanks exposed to an air/gas environment also identified general corrosion as a potential aging mechanism. As discussed above, these tanks are located inside buildings and are each vented by a 2" vent valve. There is limited air exchange through the vent valves. Therefore the rate of general corrosion is expected to be low. However, even assuming a corrosion rate of 76 mils in 60 years (as calculated above), loss of pressure boundary integrity will not occur because adequate wall thickness will remain. The approximate wall thickness of 1 inch schedule 80 piping is 180 mils. The wall thickness of components, such as valves, is even greater. The minimum wall thickness required to address pressure retention for these components is 2 mils. Therefore, the remaining wall thickness of 104 mils is more than adequate to meet design requirements and adequate corrosion allowance exists for these components. Additionally, a review of St. Lucie plant-specific operating experience did not identify internal corrosion of these components as an aging effect requiring management. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the CCW surge tanks (which are exposed to an air/gas environment) is not an aging effect requiring management.

Finally, it should be recognized that loss of pressure boundary integrity above the water line will not result in loss of inventory or impact CCW surge tank system intended function since the CCW surge tanks are normally vented tanks.

RAI 3.3.9 - 3

The applicant relies on detection of leakage for managing loss of material on the inside surface of several components that are exposed to raw water. The presence of leakage from a component, however, would indicate that the component could not perform its intended function as a pressure boundary. The applicant is requested to justify why the use of this program alone is adequate for managing loss of material from the inside surface of the components that are exposed to raw water.

FPL Response

The response below supercedes the response to RAI 3.3.9-3 transmitted in FPL Letter L-2002-159 dated September 26, 2002. This response is being revised to address use of both the Systems and Structures Monitoring Program and the Intake Cooling Water Inspection Program for aging management.

As described in LRA Appendix B, Subsection 3.2.14 (page B-57), the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping, and fittings at selected locations of Intake cooling Water (ICW) by leakage inspection to detect the presence of internal corrosion. These locations mostly encompass small bore piping components not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4" instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the Component Cooling Water heat exchangers below design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:

a. Maintenance history shows that localized failures of cement lining result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage, which provides adequate time for repairs before the system function is degraded.

b. For small valves, piping and fittings leakage does not affect the system function because the small size of these components limits the leakage. These lines are either constructed of corrosion resistant materials (monel, bronze, aluminum bronze) or are epoxy coated carbon steel. Because the joints in carbon steel lines may be exposed to salt water, a specification was developed to provide for the replacement of these lines with monel on an "as required" basis during inspections or when leaks are identified. To date, approximately 75% of the epoxy coated, small carbon steel piping and fittings, and all of the small valves, have been replaced with corrosion resistant materials. Plant operators walk down ICW as part of normal shift activities, and would note any leaks that were present. When leaks are identified, they are immediately documented under the corrective action program and receive prompt engineering evaluation and corrective actions. The operating and maintenance history of this equipment demonstrates that leakage for this equipment has not been significant.

In addition to the above process, periodic crawl-through inspections of the large bore piping, as described in the Intake Cooling Water Inspection Program (LRA Appendix B Subsection 3.2.20 page B-43), are conducted to identify, evaluate and repair any component degradations. Although no crawl-through inspections can be performed on the small-bore piping, the connections between the small bore and large bore piping, which are the most likely locations for corrosion, are inspected. Therefore, the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of Intake Cooling Water.

Table 3.3-9 of the LRA (pages 3.3-59, 3.3-60, and 3.3-61) is revised as shown below:

TABLE 3.3-9
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves (strainer bypass, strainer backwash, and spent fuel pool makeup)	Pressure boundary	Carbon steel Cast iron (Unit 1 only)	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Piping/fittings (strainer bypass, strainer backwash, and spent fuel pool makeup) [VII C1. 1.1]	Pressure boundary	Stainless steel	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Piping/fittings (strainer bypass, strainer backwash, and spent fuel pool makeup)	Pressure boundary	Stainless steel	Air/gas	None	None required
		Carbon steel	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Valves (vents, drains, and instrumentation) [VII C1. 2.1]	Pressure boundary	Stainless steel Aluminum bronze Bronze	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Valves (vents, drains, and instrumentation)	Pressure boundary	Carbon steel Monel	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Piping/fittings (vents, drains, and instrumentation) [VII C1. 1.1]	Pressure boundary	Stainless steel Aluminum bronze	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Piping/fittings (vents, drains, and instrumentation)	Pressure boundary	Carbon steel Aluminum brass Monel	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
		Fiberglass (Unit 2 only)	Raw water – salt water	Cracking	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program
Tubing/fittings	Pressure boundary	Stainless steel	Raw water – salt water	Loss of material	Systems and Structures Monitoring Program Intake Cooling Water Inspection Program

RAI 3.3.15 - 1

In Table 3.3.15, "Ventilation," the applicant identifies, for the control room air-conditioning subsystem, loss of material as an applicable aging effect for the carbon steel filter housing, which is internally exposed to an air/gas environment, but not for carbon steel component valves and piping/fittings that are exposed to the same environment. Please explain this discrepancy.

FPL Response

The response below supercedes the response to RAI 3.3.15-1 transmitted in FPL Letter L-2002-159 dated September 26, 2002. This response is being revised to describe the use of the MCIC report referenced in the response.

The carbon steel valves and piping/fittings identified in LRA Table 3.3-15 (pages 3.3-75 and 3.3-76) exposed to an air/gas environment are associated with Unit 1 Control Room Air Conditioning outside air intake. The internal air/gas environment for the piping and valves is outside air. As discussed in LRA Appendix C, Section 5.1 (page C-11) carbon steel is considered susceptible to loss of material due to general corrosion in this environment. As such, the aging management review of these components evaluated the potential impact of this aging effect on component intended function. Unlike the carbon steel ventilation housings which are constructed of heavy gage sheet metal, the carbon steel piping evaluated is schedule 40 and has a nominal thickness of 0.280 inches. The valves, which are wafer-type butterfly valves, have a body thickness greater than one inch. Utilizing conservative corrosion rates for Steel category "A", "Inland" environment, and "Average Reduction in Thickness, mils" from Tables 6-1 and F-1 of MCIC Report, July, 1986, "Corrosion of Metals in Marine Environment" by J. A. Beavers, G. H. Koch and W. E. Berry, the worst case internal loss of material is calculated to be 76 mils (3 mils/year x 8 years + 1 mil/year x 52 years) over the life of the plant. The "Average Reduction in Thickness" column is applicable since the aging mechanism of concern for the internal surfaces of the Control Room Air Conditioning outside intake valves/piping/fittings is general corrosion and thus, uniform loss of material is expected. Note that due to the location of these components and their limited air exchange with the environment, aggressive chemical species will not be present and significant pitting corrosion is not expected. The "Inland" environment data is applicable based upon expected conditions for the air space inside the Control Room Air Conditioning intake components. The Control Room Air Conditioning outside intake line is located inside the Reactor Auxiliary Building and is normally isolated. Thus, high humidity of inland tropical environment without aggressive species, such as chlorides is applicable. Based upon the above, the corrosion rate as derived from Table 6-1 is 2.8 mils for the first year, 2.3 mils for the second year (i.e., 5.1 cumulative), 3.2 mils for the third and fourth years (i.e. 8.3 cumulative), and approximately 1.1 for each of the next 4 years (i.e., 12.6 mils total for 8 years). For conservatism, a corrosion rate of 3 mils/year was assumed for the first 8 years, followed by a 1 mil/year corrosion rate for the remainder of plant life.

These corrosion rates are based upon comprehensive evaluations of corrosion damage to steel exposed to tropical atmosphere in the Panama Canal Zone. As expected, the corrosion rate decreases with time due to the buildup of an oxidation layer which will tend to provide some protection of the bare metal underneath. Thus, based upon this worst case corrosion rate, the remaining piping wall thickness is 0.204 inches. Since this portion of the ventilation system is non-pressurized, the remaining wall thickness must only address structural loads and it is concluded that adequate corrosion allowance exists for these components. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the Control Room Air Conditioning outside air intake (which are exposed to an air/gas environment) is not an aging effect requiring management.

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 response below supercedes the response to RAI 3.5-1 transmitted in FPL letter L-2002-157 dated September 26, 2002. This response is being revised to clarify the aging effects requiring management for concrete components.

The analysis of possible aging effects for reinforced concrete components in the Containments and Other Structures are summarized in the LRA Subsections 3.5.1.3 and 3.5.2.3 (pages 3.5-9 and 3.5-24, respectively). 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 (LRA Appendix B Subsection 3.2.14 page B-57) for managing aging (including cracking, loss of material, and change in material properties) 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 3.6 - 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

The response below supercedes the response to RAI 3.3.9-3 transmitted in FPL Letter L-2002-159 dated September 26, 2002. This response is being revised to discuss fuse holders.

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-environmentally qualified (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-specific 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 piping and components. Most areas of the St. Lucie Units 1 and 2 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 piping and components. Although the Reactor Auxiliary Buildings contain Blowdown 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 (page 3.6-6) 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 (page 3.6-3), 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 2 kV to 15 kV, 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, radiation, or moisture 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, radiation, or moisture 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.

In addition, as described in FPL's response to RAI 3.6-2, this program also includes non-EQ cables and connections associated with sensitive, low-level signal circuits. Note that the only circuits within the scope of license renewal for St. Lucie that fall into this category are those associated with the source, intermediate and power range neutron detectors. As indicated in FPL's response to RAI 3.6-2, the containment radiation monitors (General Atomic, LRA Subsection 4.4.1.17, page 4.4-24) and associated cables (Unit 1 - Boston Insulated Wire, LRA Subsection 4.4.1.6, page 4.4-12, and Raychem Cables, LRA Subsection 4.4.1.33, page 4.4-40, and Unit 2 – Rockbestos Cables, LRA Subsection 4.4.1.7, page 4.4-13) both inside and outside containment at St. Lucie are managed by the EQ program, and thus require no further discussion. Non-EQ cables and connections associated with sensitive, low-level signal circuits are susceptible to induced currents from the high voltage power supply if insulation resistance diminishes.

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.

For the cables associated with the source, intermediate and power range neutron detectors, routine calibration tests are performed, based on technical specification requirements, for indication of possible age-related degradation of insulation that could affect these circuits.

Detection of Aging Effects –

Cable and connection jacket surface anomalies are precursor indications of conductor insulation aging from heat, radiation, or moisture in the presence of oxygen and may indicate the existence of an adverse localized equipment environment. 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 for each unit. EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments," will be used as guidance in performing the inspections.

For the cables associated with the source, intermediate and power range neutron detectors, the routine calibration tests described above will be used to identify the potential existence of age-related degradation.

Monitoring and Trending –

Trending actions for visual inspections of in containment accessible non-EQ cables, and connections are not included as part of this program because the ability to trend inspection results is limited.

Although not a requirement in GALL program XI.E2, test results of calibration reports for the source, intermediate and power range neutron detectors that are trendable will be evaluated to provide additional information on the rate of degradation for these cables.

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.

For the cables associated with the source, intermediate and power range neutron detectors, the acceptance criteria is specified in plant procedures. These acceptance criteria are specified in terms of voltage and current limits.

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, radiation, or moisture 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, radiation, or moisture 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 St. Lucie Non-EQ Cable and Connection Aging Management Program described above for the Containments is consistent with GALL Report program XI.E1, except that it has been enhanced to include actions related to non-EQ cables and connections associated with sensitive circuits. Accordingly, this program will provide reasonable assurance that non-EQ cables and connections will maintain their intended functions during the period of extended operation. A description of this program will be added to the UFSAR Supplements for St. Lucie Units 1 and 2 in LRA Appendix A.

At the NRC public meeting on November 6, 2002, FPL was requested to provide details of the St Lucie Units 1 and 2 aging management review (AMR) of fuse holders, and to provide a commitment to address a revised interim staff guidance (ISG) document regarding fuse holders (note that this ISG has not been issued and is currently not available to FPL). The NRC indicated that the ISG is being revised to address information provided in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants". With regard to the AMR of fuse holders, as stated in FPL's response to RAI 2.5-1, fuse holders that were not part of a larger, active assembly were scoped, screened, and determined to be subject to an AMR. The only fuse holders determined to require an AMR were those installed to address the requirements of Regulatory Guides 1.63 and 1.75 to provide double isolation for non-safety related loads powered from safety related power supplies. These fuses are located in a number of isolation panels located in the Reactor Auxiliary Buildings. These panels are enclosures that contain the fuses, fuse holders and cables associated with them. As provided in LRA Section 3.6 (pages 3.6-1 through 3.6-16), the AMR for connections (including the fuse holders above) addressed the aging mechanisms of moisture, oxygen, vibration and tensile stress, voltage stress, radiation, and heat. The AMR also addressed adverse localized environments. As indicated above, the AMR concluded that there were no aging effects requiring management for electrical connections.

Based on FPL's review of NUREG-1760, the only aging mechanism not explicitly addressed in the LRA for fuse holders is wear/fatigue due to repeated insertion and removal of fuses. For St. Lucie, the fuse holders subject to an AMR are those associated with fuses that are not routinely removed for maintenance and/or surveillances. When these circuits need to be de-energized, power is removed at the safety related power supplies (Motor Control Centers, Power Panels, etc.). Additionally, two of the conclusions in NUREG-1760 are worth noting:

- "This study has found that fuses are susceptible to aging degradation that can lead to failure, however, the occurrence is infrequent."
- "The data indicate that the incidence of fuse failures is not increasing with age presently, indicating fuse aging is being managed."

Based on the information provided above, FPL concludes that there are no aging effects requiring management for fuse holders. However, the NRC has requested that FPL make a commitment to address the ISG regarding fuse holders currently under revision by the NRC. Accordingly, FPL will address the revision to the ISG regarding fuse holders (when issued) as applicable to St. Lucie.

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 response below supercedes the response to RAI 3.6-2 transmitted in FPL Letter L-2002-157 dated September 26, 2002. This response is being revised to clarify that cables associated with radiation monitors are managed by the Environmental Qualification (EQ) Program.

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.

As stated in FPL's response to RAI 3.6-1, the only non-EQ cables and connections associated with sensitive, low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the source, intermediate and power range neutron detectors. Note that the containment radiation monitors (General Atomic, LRA Subsection 4.4.1.17, page 4.4-24) and associated cables (Unit 1 - Boston Insulated Wire, LRA Subsection 4.4.1.6, page 4.4-12, and Raychem Cables, LRA Subsection 4.4.1.33, page 4.4-40, and Unit 2 – Rockbestos Cable, LRA Subsection 4.4.1.7, page 4.4-13) both inside and outside containment at St. Lucie are managed by the EQ program, and thus require no further discussion. FPL does not consider an additional aging management program to address sensitive, low-level signal circuits to be necessary for the following reasons:

1. As noted above, the aging management reviews performed determined there were no aging effects requiring management.
2. 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.

3. 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."

Additionally, a review of other license renewal Safety Evaluation Reports indicates acceptance of visual inspections for managing aging of cables and connections.

However, based on discussions with the NRC in public meetings on September 4 and 5, 2002, FPL has included activities in the aging management program proposed in the response to RAI 3.6-1 to address aging of the sensitive circuits associated with the source, intermediate and power range neutron detectors. The results of routine calibration tests for these circuits will be used to facilitate detection of adverse localized environments. See FPL's response to RAI 3.6-1 for further details.

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.

FPL Response

The response below supercedes the response to RAI 4.3-3 transmitted in FPL Letter L-2002-165 dated October 10, 2002. This response is being revised to include the nozzle materials.

For St. Lucie Units 1 and 2, detailed environmental fatigue calculations were performed for each of the components identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," for the older vintage Combustion Engineering (CE) plant. The six fatigue-sensitive component locations chosen for the early-vintage CE pressurized water reactor calculations were:

(1) the reactor pressure vessel shell and lower head,

(2) the reactor pressure vessel inlet and outlet nozzles,

(3) the pressurizer surge line elbow,

(4) the Reactor Coolant System piping charging system nozzle,

(5) the Reactor Coolant System piping safety injection nozzle,

(6) the shutdown cooling system Class 1 piping.

Counting the reactor pressure vessel inlet and outlet nozzles as separate locations, seven different component locations were evaluated for each unit.

The St. Lucie calculations were performed using the appropriate methodology contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," for carbon/low alloy steel material, or NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel material, as appropriate. These calculations, along with the original design basis calculations, are summarized in Tables 4.3-3.1 and 4.3-3.2. The environmental adjustments to the cumulative usage factor (CUF) results shown in Tables 4.3-3.1 and 4.3-3.2 are considered to be conservative, and are applicable for 60 years of plant operation.

Based on the results shown in Tables 4.3-3.1 and 4.3-3.2, all candidate locations for environmental fatigue effects, except for the following locations, are acceptable for 60 years of operation (i.e., the cumulative usage factor is less than the allowable value of 1.0):

- St. Lucie Unit 1 pressurizer surge line
- St. Lucie Unit 2 pressurizer surge line

As shown in Tables 4.3-3.1 and 4.3-3.2, the maximum CUF for the surge line elbow for both St. Lucie units was calculated to be above 1.0 when environmental effects were considered. Based on this and the refined nature of the existing evaluations, the surge lines are candidate components for additional inspection considerations during the license renewal period. Aging management for the pressurizer surge lines is described in LRA Subsection 4.3.3 (page 4.3-5) and will be included in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program described in LRA Appendix B Subsection 3.2.2.1 (page B-25).

Table 4.3-3.1
Summary of St. Lucie Unit 1
Environmental Fatigue Calculations

No.	Component	Material	Design Cumulative Usage Factor	Environmental F_{en} Multiplier[1]	Environmental Cumulative Usage Factor	Allowable Value
1	Outlet Nozzle	SA-508 Class 2 low alloy steel	0.0788	2.04	0.1607	1.0
2	Inlet Nozzle	SA-508 Class 2 low alloy steel	0.0496	2.41	0.1198	1.0
3	Vessel Shell and Bottom Head	SA-533 Grade B Class 1 low alloy steel	0.0031	1.77	0.0055	1.0
4	Charging Inlet Nozzle	SA-105 Grade II carbon steel	0.1404	1.64	0.2297	1.0
5	Safety Injection Nozzle	SA-182 Grade F1 low alloy steel	0.1539	1.77	0.2728	1.0
6	Surge Line Elbow	SA-182 Type 316 stainless steel	0.9370	7.79	7.2998	1.0
7	Shutdown Cooling Piping	A-376 Type 304 stainless steel	0.0611[2]	15.17	0.9266	1.0

NOTES:

1. These multipliers represent an average of all F_{en} values determined for each individual load pair in the fatigue calculation.
2. The original CUF for the limiting shutdown cooling piping location was 0.5612. The CUF was recalculated to remove excess conservatism in the analysis resulting in a CUF of 0.0611. The original analysis included emergency and faulted events in the fatigue analysis which is not required by the ASME Code.

**Table 4.3-3.2
Summary of St. Lucie Unit 2
Environmental Fatigue Calculations**

No.	Component	Material	Design Cumulative Usage Factor	Environmental F_{en} Multiplier	Environmental Cumulative Usage Factor	Allowable Value
1	Outlet Nozzle	SA-508 Class 2 low alloy steel	0.3775	2.34	0.8825	1.0
2	Inlet Nozzle	SA-508 Class 2 low alloy steel	0.2285	2.15	0.4909	1.0
3	Vessel Shell and Bottom Head	SA-533 Grade B Class 1 low alloy steel	0.0017	2.37	0.0039	1.0
4	Charging Inlet Nozzle	SA-182 Type F-316 stainless steel[1]	0.0577	2.55[2]	0.1468	1.0
5	Safety Injection Nozzle	SA-182 Grade F1 low alloy steel	0.0644	1.77	0.1141	1.0
6	Surge Line Elbow	Stainless steel	0.9370	7.75	7.2603	1.0
7	Shutdown Cooling Piping	A-376 Type 304 stainless steel	0.0485	15.35	0.7451	1.0

NOTES:

1. Piping side of the safe end.
2. Multiplier based on operating temperatures not exceeding 200°C (Reference St. Lucie Unit 2 UFSAR, Table 9.3-8, "Chemical and Volume Control System Process Flow Data," CVCS Location 13).

Additionally, at the request of an NRC reviewer during a telephone conference conducted on November 20, 2002, FPL agreed to revise LRA Appendices A1 and A2 (proposed UFSAR Supplements for St. Lucie Units 1 and 2 respectively), Subsection 18.3.2.3, to include the options identified in the evaluations of the pressurizer surge lines. The commitments are similar to the commitments made for license renewal of Turkey Point Units 3 and 4. Accordingly, the last paragraph of Subsection 18.3.2.3 in LRA Appendices A1 and A2 will be replaced with the following:

"For the pressurizer surge line, FPL will inspect the limiting surge line welds during the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program third and fourth inspection intervals, and prior to entering the extended period of operation. The results of these inspections will be utilized to assess fatigue of the surge lines. In addition to these inspections, environmentally assisted fatigue of the surge lines will be addressed using one or more of the following approaches:

1. Further refinement of the fatigue analysis to lower the CUF(s) to below 1.0, or
2. Repair of the affected locations, or
3. Replacement of the affected locations, or
4. Manage the effects of fatigue by an NRC approved inspection program."

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.

FPL Response

The response below supercedes the response to RAI 4.6.3-3 transmitted in FPL Letter L-2002-165 dated October 10, 2002. This response is being revised to provide references for FPL and NRC correspondence addressing the failure analysis and repair of the core support barrel, to discuss core bypass flow assuming a repair failure, and to provide repair plug flange and cylinder thickness.

See response to RAI 4.6.3-2.

Correspondence associated with the core support barrel repairs included:

- J. W. Williams Jr. (FPL) letter to J. R. Miller (NRC) L-84-29, "Reactor Vessel Internals and Thermal Shield; Plant Recovery Program Final Integrity and Stability of Internals – Conclusions and Finding," dated February 10, 1984 provided a discussion of the identification, cause and repairs to the core support barrel.
- J. R. Miller (NRC) letter to J. W. Williams, Jr. (FPL), "Thermal Shield Recovery Program," dated March 14, 1984 provided the safety evaluation report for the thermal shield recovery program.
- J. W. Williams Jr. (FPL) letter to J. R. Miller (NRC) L-84-312, "PSL-1 Thermal Shield Failure at St. Lucie Nuclear Generating Unit No. 1" Report – Forensic Technologies International Corporation, dated November 7, 1984 provided the independent assessment of the thermal shield failure.
- C. O. Woody (FPL) letter to A. C. Thadani (NRC) L-86-181, "Thermal Shield Recovery Program Final Core Support Barrel Inspection Report (Post-Cycle 6)," dated April 25, 1986 provided the results of the core support barrel inspection required by the safety evaluation report.

FPL evaluated the change in core bypass leakage flow assuming a failure of the largest patch plate (lug location No. 1). It is assumed that four patch plugs used to anchor the patch plate also fail. Since the assumed failed patch assembly covers the largest through-wall area in the core support barrel, the core bypass leakage flow would be the maximum value predicted for a failure of a single repaired area.

The assumed failure of the core support barrel plug or patch assembly reduces the hydraulic resistance of the reactor; the net effect being that the reduced system resistance intersects the pump performance curve at a larger system flow rate. The larger system flow rate partially offsets the increased core bypass leakage flow due to the failed patch assembly.

The resulting predicted best estimate reactor vessel flow rate ratios and core flow rate ratios for normal operation and a failed patch assembly were compared. The difference in core flow from normal operation to failure of the largest core support barrel patch was determined to be a increase of core bypass flow of 2.94%.

The effects of assuming an increased core bypass flow (3.1%) which envelops the loss of the largest core support barrel patch were evaluated on St. Lucie Unit 1 Design Bases Events, Limiting Conditions For Operation and Limiting Safety System Settings. The evaluation demonstrated that the predicted effects of a hypothetical failure of the core support barrel patch are acceptable.

Repair plugs flange and cylinder thickness are provided below:

Plug Size	**Flange Thickness** (inches)	**Cylinder Thickness** (inches)
3 inch	0.215	0.060
5 inch	0.313	0.060
8 inch	0.375	0.080
3 inch Patch Plug	0.215	0.100

RAI 4.6.4 - 1

Consistent with the staff's safety evaluation dated February 8, 2002, on Combustion Engineering Owners Group (CEOG) Topical Report No. CE NPSD-1198-P, Revision 00, perform a plant-specific general corrosion rate analysis calculation for the bounding half-nozzle repair implemented at St. Lucie Units 1 and 2. Provide a discussion or evidence which demonstrates that the general corrosion rate analysis calculation provided in CEOG Topical Report No. CE NPSE-1198-P, Revision 00, is bounding relative to the plant-specific analysis.

FPL Response

The response below supercedes the response to RAI 4.6.4-2 transmitted in FPL Letter L-2002-165 dated October 10, 2002. This response is being revised to address specific NRC review comments and FPL's review of recently submitted WCAP-15973-P, Revision 00 (CE-NSPD-1198-P, Revision 01).

The recent reactor head conditions discovered at Davis-Besse demonstrated that significant corrosion of carbon and low alloy steels can occur under conditions where boric acid concentrates in an aerated environment. The corrosion rate was estimated to have progressed at up to 2 inches per year. The environment that supported the high corrosion rate was concentrated solutions or wet deposits of boric acid and leakage at a rate to cause local cooling of the reactor vessel head.

Following a nozzle replacement, there is no mechanism for concentrating boric acid in the crevice region, because there is no active external leakage, and the corrosion rates that will occur in the crevice region will be low. Several laboratory studies (described in CEOG Topical Report Nos. CE NPSD-1198-P, Revision 00 and WCAP-15973-P, Revision 00) in which carbon and low alloy steels were exposed to primary coolant at deaerated, high temperature (operating) conditions, aerated intermediate temperature (startup) conditions, and fully aerated low temperature (shutdown) conditions demonstrated that the high corrosion rates observed in concentrated solutions or wet deposits of boric acid will not occur under these operating conditions. Thus, Davis-Besse and similar events involving Reactor Coolant System components and fasteners are not applicable to a nozzle replacement because of the dissimilarity in the environmental conditions.

Topical Report Nos. CE NPSD-1198-P and WCAP-15973-P developed corrosion rates for high temperature (normal operating) conditions, intermediate temperature (startup) conditions and low temperature aerated (shutdown) conditions. For this evaluation, the corrosion rates defined in this topical report are considered applicable. The overall corrosion rate for a plant is the sum of the corrosion for each condition, based on the percentage of time at that condition. The topical report assumed that Combustion Engineering plants would be operating at high temperature conditions for 88% of the time, at intermediate temperature startup conditions for 2% of the time, and at shutdown conditions for 10% of the time.

The greatest contribution to the overall corrosion rate is the corrosion occurring during shutdown conditions. Thus, any operation with capacity factors greater than 88% (time at shutdown of less than 10%) will be bounded by the corrosion rates defined in Topical Report Nos. CE NPSD-1198-P and WCAP-15973-P. Based on St. Lucie plant-specific operating experience and projected future operations and outage schedules, the assumptions of the topical report are conservative (actual St Lucie Units 1 and 2 capacity factors are greater than 88%) and will bound the actual corrosion rates for St. Lucie Units 1 and 2.

An evaluation was performed to determine the design lifetime of the Alloy 600 nozzle replacements based on the allowable corrosion rates. The evaluation concluded that the most limiting nozzles are the St. Lucie Units 1 and 2 hot leg nozzles with lifetimes of 89.2 and 90.5 years, respectively. The remaining nozzles have lifetimes ranging from 94.7 years to 358 years. These lifetimes are significantly longer than 60 years. Therefore, ASME Code requirements will not be exceeded prior to the end of the period of extended operation.

The corrosion rates described above were based on data from autoclave tests in which carbon and low alloy steel specimens were exposed to borated water test solutions. In these tests, relatively small specimens were tested in relatively large volumes of simulated primary coolant and, as a result, best describe the corrosion performance of carbon and low alloy steels exposed to the bulk primary coolant, as would be the case if a section of cladding were removed. In the case of a half-nozzle replacement, the steels will actually be exposed to solutions confined to the crevice regions where the volumes of solution are small and where the solutions are confined and not readily replenished (refreshed). Under such conditions, corrosion rates will be lower than the rates described above. Further, corrosion of the steels in the crevice region will be accompanied by the formation of iron oxide corrosion products. The corrosion products occupy a greater volume than the non-corroded base metals from which they came; the ratio of corrosion product volume to base metal volume for iron alloys is about two. Since the corrosion products cannot readily exit the crevice region, they will eventually fill the crevice and prevent access of the primary coolant to the steels, which will in turn further reduce the corrosion rate. Although oxides are typically porous and would permit some access to the steels, the closed crevice geometry, with only one narrow gap, will confine the iron oxide corrosion products to the crevice and prevent any loss from flaking or spalling. Continued corrosion will only result in the corrosion products becoming more dense and less permeable to the primary coolant with the result that the corrosion process eventually will stifle.

Topical Report Nos. CE NPSD-1198-P and WCAP-15973-P estimated the amount of corrosion required to pack the crevice and stifle the corrosion process. Assuming a nominal radial crevice of 0.005 inch with 0.005-inch tolerance on the hole results in a maximum crevice size of 0.010 inch. If the ratio of corrosion product to base metal is conservatively assumed to be 2.0, the increase in hole diameter that would pack the crevice and stifle the corrosion process is less than 20 percent of the ASME Code allowed increase for St Lucie 1 and 2.

In addition, FPL has reviewed WCAP-15973-P Revision 00 (CE-NSPD-1198-P, Revision 01) dated November 2002 and determined that the conclusions of the St. Lucie plant-specific evaluation are not changed.

The evaluations described above were conducted in accordance with the methods of Topical Report Nos. CE NPSD-1198-P and WCAP-15973-P. The evaluations demonstrate that the carbon and low alloy steel Reactor Coolant System components at St Lucie 1 and 2 will not be unacceptably degraded by general corrosion as a result of the implementation of replacements of small diameter Alloy 600 nozzles. Although some minor corrosion may occur in the crevice region of the replaced nozzles, the degradation will not proceed to the point where ASME Code requirements will be exceeded before the end of plant life, including the period of extended operation.

Further, a review of laboratory corrosion test data and field experiences indicate that the conditions such as the reactor vessel head corrosion that occurred at Davis-Besse involving significant boric acid corrosion of reactor components and parts are not applicable to the Alloy 600 nozzle replacements because of the dissimilarity in the environmental conditions of the two cases.

RAI 4.6.4 - 2

Consistent with the staff's safety evaluation dated February 8, 2002, on CEOG Topical Report No. CE NPSD-1198-P, Revision 00, justify the conclusion in the topical report that existing flaws in ASME Class 1 nozzle Alloy 182 weldments will not grow into the adjacent ferritic pipes or vessels during the extended periods of operation. Review the reactor coolant system chemistry history over the last two operating cycles for the St. Lucie Units 1 and 2. Confirm that a sufficient hydrogen over-pressure for the reactor coolant system has been implemented at the facilities and that the ingress of dissolved elemental oxygen, halide, and sulfate into the reactor coolant over this period was adequately managed and controlled (i.e., minimized to acceptable levels).

FPL Response

The response below supercedes the response to RAI 4.6.4-2 transmitted in FPL Letter L-2002-165 dated October 10, 2002. This response is being revised to include the St. Lucie plant-specific evaluation.

Based on issues identified with the fatigue analysis in CEOG Topical Report No. CE NPSD-1198-P, a St. Lucie plant-specific evaluation (Attachments 2 and 3 to this letter) of the small bore nozzles located in the hot leg piping and the pressurizers for St. Lucie Units 1 and 2 has been completed using plant-specific data. These nozzles are the locations where half-nozzle or similar repairs would be utilized, thereby leaving flaws in the original weldments, which could potentially grow into adjacent ferritic material. Postulated flaws were assessed for flaw growth and flaw stability as specified in the ASME Code, Section XI. The results demonstrate compliance with the requirements of the ASME Code, Section XI. The St. Lucie Units 1 and 2 UFSAR Supplements (LRA Appendix A1 Subsection 18.3.8 page A1-47 and Appendix A2 Section 18.3.7 page A2-44, respectively) will be revised to recognize the plant-specific evaluation and the revised Topical Report No. WCAP-15973-P.

Additionally, based on a telephone conference between FPL and NRC on November 20, 2002, FPL agreed to submit an ASME Code relief request for half nozzle replacements which have already been installed, and for those which may be implemented in the future. This relief request will be submitted consistent with the requirements of the ASME Section XI program for St. Lucie Units 1 and 2 under the current operating licenses.

With regard to Reactor Coolant System (RCS) chemistry history, the Chemistry Control Program – Water Chemistry Control Subprogram described in LRA Appendix B, Subsection 3.2.5.1, (page B-32), has been ongoing at St. Lucie since initial startup and has evolved over many years. The subprogram incorporates the best practices recommended by industry organizations, with technical input and concurrence from U.S. NSSS vendors, as well as utility and water treatment experts. In addition, St. Lucie Units 1 and 2 Technical Specifications contain limits and sampling frequencies for dissolved oxygen, chloride, and fluoride for the RCS. RCS chemistry for St. Lucie Units 1 and 2 has been maintained in accordance with these requirements.

With regard to hydrogen, station operating procedures require that the over-pressure in the Chemical and Volume Control volume control tanks (VCTs) be maintained between 25 and 30 psig, and that RCS hydrogen concentrations be maintained between 25 and 50 cc/kg. The Water Chemistry Control Subprogram ensures that hydrogen concentrations in the St. Lucie RCS are maintained within specified limits by measurement of hydrogen concentrations in periodic RCS samples and adjusting hydrogen concentration in the VCTs. The Water Chemistry Control Subprogram ensures that hydrogen over-pressure in the RCS is maintained, and that the ingress of dissolved elemental oxygen, halide, and sulfate in the reactor coolant is managed and controlled.

RAI B.3.1.2 - 1

In Section 3.1.2, "Galvanic Corrosion Susceptibility Inspection Program," of Appendix B to the LRA, the applicant states that inspections will be conducted on a sampling basis. Locations selected for inspection will represent those with the greatest susceptibility to galvanic corrosion. However, there are insufficient details in the LRA concerning the program for the NRC staff to determine with reasonable assurance that the program is acceptable. Provide additional information concerning the existing program or the planned development of the program elements in the following areas:

- Explain how the greatest susceptibility locations will be determined including whether these locations will be selected for each system or for all the systems.
- Explain what documents or information will be used to define the inspection interval, sample size, inspection criteria, and corrective actions.
- Explain how information concerning the inspections of the susceptible locations, the results of the inspections, and corrective actions will be managed, tracked, and evaluated.

FPL Response

The response below supercedes the response to RAI B.3.1.2-1 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to specifically address environments and operating experience for the other systems (Instrument Air, Ventilation, and Fire Protection).

Significant galvanic corrosion has not been experienced and is not anticipated in treated water systems due to the high purity of the water and its low conductivity. The Galvanic Corrosion Susceptibility Inspection Program (LRA Appendix B Subsection 3.1.2 page B-11) was developed to quantify the significance of loss of material due to this corrosion mechanism and provide for managing the effects of aging, if required. This program constitutes a one-time inspection of selected locations in various systems which have been identified as potentially susceptible. The majority of these systems have internal environments of treated water.

The other systems have internal environments of condensed atmosphere in portions of Instrument Air and Ventilation, and "raw water - city water" in Fire Protection. As stated in LRA Appendix C, Section 4.1.2 (page C-7), "raw water – city water" is potable water. The water has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. A review of the St. Lucie plant-specific operating experience for these other systems (i.e., Instrument Air, Ventilation, and Fire Protection) also did not identify significant galvanic corrosion, therefore, they are included in the program for one-time inspection.

First Bullet

Since the inspection of all locations with the potential for galvanic corrosion is not practical, an engineering specification will be developed to provide the methodology for identifying those galvanic couples where corrosion is most likely to occur and where inspection results can be used to bound less susceptible locations. This engineering specification will also provide methods for conducting inspections, evaluation of inspection data and documentation of results.

Selection of locations with greatest susceptibility to galvanic corrosion is based upon the following:

(1) How far apart the two dissimilar metals are on the galvanic series chart. The further apart, the higher the corrosion rate. Note that all stainless steels addressed by the Galvanic Corrosion Susceptibility Inspection Program are considered "passive" as described in ASTM Standard G 82-98, "Development and Use of a Galvanic Series for predicting Galvanic Corrosion performance". As previously discussed, this program addresses the potential for galvanic corrosion in treated (high purity) water systems. Stainless steels in this environment will develop and maintain a passive protective oxide coating.

(2) The conductivity of the electrolyte. The more conductive the electrolyte, the higher the corrosion rate.

(3) The relative size of the anode and cathode. A smaller anode surface area will result in a larger corrosion rate.

The overall susceptibility of each galvanic couple in each system is assessed and ranked based upon consideration of each of the above factors. Those with greatest susceptibility are then recommended for inspection. Those that are not selected for inspection are verified to be bounded based upon electrical potential of dissimilar materials, purity of water (i.e., conductivity), and relative size of anode and cathode. For those cases where the combination of two influencing factors do not provide a conclusive ranking, the particular galvanic cell is selected for inspection. The selection process will ensure that a variety of environments are addressed by inspection including treated water - other, borated water, raw water - city water (fire protection), and air/ gas - wetted air (condensation).

<u>Second Bullet</u>

The results of the initial inspections will be assessed to determine the need for follow-up inspections. Although not anticipated, for any case where loss of material is identified, the scope and frequency of follow-up inspections will be based upon the measured wall thickness, calculated corrosion rate, projected wall thickness, and will ensure the minimum required wall thickness is maintained pursuant to the applicable code requirements. (See FPL responses to RAIs B.3.1.3-1 and B.3.1.3-2.)

<u>Third Bullet</u>

The results of the one-time inspection will be documented in accordance with the Corrective Action Program as discussed in LRA Appendix B Section 2.0 (page B-5).

RAI B.3.2.5 - 2

In Section 3.2.5.1 of Appendix B to the LRA, the applicant states that the Water Chemistry Control Subprogram was developed in accordance with the guidance in TR-107396, "Closed Cycle Cooling Water System," published October 1997 by the Electric Power Research Institute (EPRI) and is consistent with the 10 attributes of the AMP X1.M21, "Closed-Cycle Cooling Water System,"" in the Generic Aging Lessons Learned (GALL) report, with the exception that this subprogram does not address surveillance testing and inspection. The applicant further states that the Intake Cooling Water Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program. The Intake Cooling Water Inspection Program includes inspection of only those closed-cycle cooling water (CCW) system components that are exposed to raw water, which are the CCW heat exchanger tubes, tubesheet channels, and doors. The GALL report recommends inspecting these components and other CCW system components, which are exposed to treated water and susceptible to loss of material. Explain this discrepancy between the Chemistry Control Program, as descriptions in Section 3.2.5.2 of Appendix B to the LRA and the AMP X1.M21 in the GALL report.

FPL Response

The response below supercedes the response to RAI B.3.2.5-2 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to provide additional St. Lucie plant-specific operating experience.

Aging Management Program (AMP) X1.M21, "Closed-Cycle Cooling Water System," of the Generic Aging Lessons Learned (GALL) Report states that the aging management program monitors the effects of corrosion by surveillance testing and inspection (in accordance with standards in EPRI TR-107396, "Closed Cycle Cooling Water System") to evaluate system and component performance. The existing St. Lucie Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram (LRA Appendix B Subsection 3.2.5.2, page B-33), in conjunction with the Intake Cooling Water System Inspection Program (LRA Appendix B Subsection 3.2.10, page B-43) and periodic surveillance testing is consistent with the GALL Closed-Cycle Cooling Water System Program with respect to parameters monitored or inspected. The parameters monitored by the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram for the purposes of License Renewal aging management are based on the recommendations of EPRI TR-107396. Non-chemistry parameters monitored by periodic surveillance testing include pump flow and discharge and suction pressures, heat exchanger flow and inlet and outlet temperatures, and emergency diesel generator performance. The component cooling water heat exchangers are periodically inspected under the Intake Cooling Water System Inspection Program.

As part of the aging management review process for Component Cooling Water, a review of St. Lucie plant-specific operating experience was performed to identify any age related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective chemistry control program. Note that many component cooling water components have been inspected in the past as part of corrective maintenance or the preventive maintenance program (e.g., periodic pump overhauls). During the past 12 months, more than thirty maintenance work orders were generated for Units 1 and 2 Component Cooling Water that require disassembly or removal of components. These work orders include repairs on instrumentation and other isolation valves, flow control valves, and check valve and relief valve internals inspections throughout the system. A majority of these components (e.g., relief and isolation valves) entail system locations where stagnant flow conditions exist. The internal condition of the components has provided additional confidence that the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram is effective.

As discussed in the response to RAI 3.3.2-1, maintenance procedures typically specify inspection criteria or reference plant quality instructions that specify internal cleanliness requirements. As an example, the maintenance procedure for relief valve removal and testing includes a visual inspection of valve and piping mating surfaces for corrosion and pitting. Additionally, the internal cleanliness criteria for Component Cooling Water would permit a tightly adherent oxide film or red oxide coating, as well as small areas of light surface rust, but pitting would not be acceptable. See RAI 3.3.2-1 for additional information regarding maintenance inspection requirements. Any significant degradation identified during these inspections would have been documented under the plant corrective action program. As such, the St. Lucie Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram was determined to be an effective program and the need for additional inspections of other component cooling water components specifically to confirm program effectiveness was determined to be unnecessary.

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.

FPL Response

The response below supercedes the response to RAI B.3.2.8-2 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to provide UFSAR references for the penetration seals, to identify the types of penetration seals, and to discuss the procedures used to inspect these seals.

As stated in the response to RAI 3.5-3, and based on the information provided in SECY-96-146 and St. Lucie plant-specific 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.

However, plant procedures do provide for the inspection of penetration seals. Currently, visual inspection of at least 10% of each type of sealed penetration is performed during each refueling outage. If changes in appearance or degradations are found, a visual inspection of an additional 10% of each type is made. The types of penetrations are defined as:

1. Mechanical penetration seals
2. Electrical penetration seals
3. Instrumentation penetration seals
4. Heating and Ventilation penetration seals

This process continues until a 10% sample with no changes or degradation is found. Samples are selected such that each seal will be inspected at least once every fifteen years.

The penetration seals and materials in use at St. Lucie are listed in LRA Table 3.5-8 (page 3.5-62), and St. Lucie Unit 1 UFSAR Appendix 9.5A, Section 3.14.3 (page 9.5A-136) and Unit 2 UFSAR Chapter 9.5A, Section 3.14 (page 9.5A-128).

Plant procedures require that the penetration seals be visually inspected for voids, gaps, holes and indications of slippage. Additionally, both sides of a fire barrier are inspected unless it is inaccessible. Discrepant conditions are documented and evaluated in accordance with the corrective action program.

Fire door inspection is currently conducted every six months.

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.

FPL Response

The response below supercedes the response to RAI B.3.2.8-3 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to address additional information requested by the NRC at public meetings on November 6 and 7, 2002.

As clarified in the above response to RAI B 3.2.8-1, the St. Lucie Fire Protection Program (LRA Appendix B Subsection 3.2.8, page B-39) is plant-specific. Fire Protection at St. Lucie is filled with water classified as "raw water – city water." As stated in LRA Appendix C, Section 4.1.2 (page C-7), this water is potable water. The water has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. Internal conditions are monitored via leakage, flow, and pressure testing. Internal loss of material can be detected by changes in flow or pressure, leakage or by evidence of excessive corrosion products during flushing of the system. The following Fire Protection procedures are credited for aging management of internal conditions of the Fire Water System:

TEST	FREQUENCY
• Wet pipe sprinkler test	semi-annual
• Fire system flush	yearly
• D/G fire sprinkler system visual integrity exam	yearly
• D/G fire sprinkler system obstruction inspection	yearly
• D/G fire sprinkler system automatic valve operation	yearly
• D/G fire sprinkler system functional test	yearly
• RAB fire sprinkler system functional test	yearly
• Yard fire hydrant flow check	yearly
• Main transformer water spray test	18 month
• Auxiliary transformer water spray test	18 month
• H_2 seal oil water spray test	18 month
• Turbine lube oil storage water spray test	18 month
• 3 year fire protection flow test	3 year
• Fire hose station flow check	3 year
• City Water Storage Tanks interior inspection	5 year

With regard to St. Lucie plant-specific operating experience, past inspections/overhauls of fire protection components normally exposed to water, such as fire water pumps, hydrants, post indicator and other valves, have not identified corrosion or degraded conditions of the internal surfaces of adjoining piping requiring corrective action.

During the recent implementation of Fire Water System modifications, pipe wall thickness measurements were taken which confirm the good internal condition of the fire main and its branches. These modifications were associated with enhancements identified prior to or during the 1998 NRC Fire Protection Functional Inspection, and included the addition of an automatic suppression system for Thermo-lag walls and the addition of new hose stations in the Reactor Auxiliary Building. Pipe wall thickness measurements were taken on 4 and 6 inch lines prior to welding and confirmed that minimal internal loss of material due to corrosion has taken place (i.e., the pipe wall thicknesses were approximately nominal). Thus, based upon the above, the current methods of monitoring internal conditions are adequate and reliable.

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

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.

FPL Response

The response below supercedes the response to RAI B.3.2.8-4 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to address additional information requested by the NRC at public meetings on November 6 and 7, 2002.

Internal and external conditions for below grade fire protection piping are monitored via leakage, flow and pressure testing. Internal and external loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. See the response to RAI B3.2.8-3 for a listing of procedures credited for managing aging effects associated with the Fire Water System. Plant-specific operating experience has shown that the current methods of monitoring internal and external conditions are adequate and reliable for Fire Protection System underground piping. This is supported by recent inspections performed on a section of underground fire water piping. The internal and external surfaces of the buried portion of the fire water piping were confirmed to be in good condition by inspections performed during recent repairs to address a section of pipe which exhibited a crack induced by settling of the Turbine Building wall. The failed section was replaced and the routing of the buried fire main was modified to eliminate the potential for recurrence of this failure. The inspection of the internal surfaces of the buried pipe found the cement lining to be in good condition with no evidence of cracking. Likewise, the external coating was found to be in overall good condition with the exception of a few places were the coating had degraded and very minor corrosion was noted. Per discussion with the System Engineer, the coating degradation was limited to a few areas the size of a quarter. Thus, based upon the above, the current methods of monitoring the condition of the Fire Water System provide 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.

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

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.

FPL Response

The response below supercedes the response to RAI B.3.2.8-5 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to include references to supporting documentation.

There have been no recent enhancements to the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39). However, based on recent periodic internal and external assessments, fire protection plant modifications have been implemented including the replacement of all Unit 2 preaction suppression system local control panels with updated equipment, replacements of Unit 1 smoke detectors with new model detectors, replacement of both Control Room fire computers with new fire panels, extended preaction system coverage in the Units 1 and 2 cable loft areas, and upgraded penetration seals (cable tray fire stops) in Unit 2. St. Lucie Unit 1 UFSAR Appendix 9.5A and Unit 2 UFSAR Chapter 9.5A Fire Protection Program Report contain a review of Fire Protection and the Fire Protection Program with respect to the applicable codes and standards.

As a result of NRC Generic Letter 92-08, corrective actions associated with Thermo-lag were initiated. The Thermo-lag corrective actions were completed and the NRC was notified (see R. S. Kundalkar (FPL) letter to NRC Document Control Desk, L-2000-83, St. Lucie Unit 1 Thermo-Lag 330-1 Summary Report, April 7, 2000 and J. A. Stall (FPL) letter to NRC Document Control Desk, L-98-165, St. Lucie Unit 2 Thermo-Lag 330-1 Summary Report, June 23, 1998).

St. Lucie also performed NFPA Code reviews of the suppression and detection systems, and, based on the findings, further evaluations and modifications were implemented (e.g., increased radiant heat shield coverage in Unit 1 and 2 Containments and improved weather resistance of exterior smoke detection systems). The NRC reviewed some of the evaluations and modifications described above during the St. Lucie Fire Protection Functional Inspection conducted in 1998 (NRC Inspection Report Nos. 50-335/98-14, 50-389/98-14). Others have been implemented subsequent to this inspection. With respect to NRC review, all changes to the Fire Protection Program and/or system are reviewed in accordance with 10 CFR 50.59 and Facility Operating Licenses DPR-67 (Unit 1) Section C.(3) and NFP-16 (Unit 2) Section C.3.20.

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.

FPL Response

The response below supercedes the response to RAI B.3.2.8-6 transmitted in FPL Letter L-2002-166 dated September 26, 2002. This response is being revised to provide a basis for the 50 year inspection of sprinkler heads.

For St. Lucie Unit 1, the oldest sprinkler heads were installed approximately one year prior to issuance of the St. Lucie Unit 1 Facility Operating License. Per St. Lucie Units 1 and 2 UFSARs, Appendix 9.5A, the St. Lucie Current Licensing Bases do not include NFPA 25 for testing and inspection of sprinkler heads. However, St. Lucie generally conforms to NFPA guidelines. St. Lucie uses city water (potable) as its water source for Fire Protection. This water was conservatively classified as "raw water" for the purpose of performing aging management reviews even though it is clean and free of contaminants compared to lake or river water used in fire protection systems at other plants. The quality of the water minimizes loss of material, as evidenced by St. Lucie's operating and maintenance experience. A fire protection system annual flush is credited for ensuring the system is clear of scale, debris and foreign material.

For dry pipe closed head sprinkler systems, procedures verify the systems are in a state of readiness by ensuring proper operation of clapper/inlet valves, visually inspecting sprinkler heads and that water and supervisory nitrogen pressure are available.

For wet pipe closed head sprinkler systems, a procedure verifies that the system alarm functions and checks for water clarity.

The results of a review of plant-specific operating history associated with the tests and inspections of these components did not identify any degraded conditions for the internal surfaces of these sprinkler systems.

Based on feedback from meetings with NRC staff conducted during the review of the Turkey Point Unit 3 and 4 LRA review and open items identified on previous license renewal applications, St. Lucie proposes to perform testing of wet pipe sprinkler heads following the guidance of NFPA 25 commencing in the year 2026 (50 years from the issuance of the original operating license on Unit 1). This enhancement will be included within the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39).

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

ATTACHMENT 2

CN-CI-02-69

EVALUATION OF FATIGUE CRACK GROWTH ASSOCIATED WITH SMALL DIAMETER NOZZLES FOR ST. LUCIE 1 & 2

NON-PROPRIETARY

Westinghouse Non-Proprietary Class 3

WESTINGHOUSE ELECTRIC COMPANY LLC

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Table Of Contents

1.0 Introduction

1.1 Background / Purpose

Typical small-bore nozzles are fabricated from Alloy 600 material and are attached to the piping and vessels with 82/182-weld material. This material is subject to Pressurized Water Stress Corrosion Cracking (PWSCC) and can result in cracks and leaks in these nozzle assemblies. Leaks in the pressure boundary must be repaired. Several repair techniques are available, such as Mechanical Nozzle Seal Assemblies (MNSAs) and the half-nozzle repair technique. These repairs relocate the pressure boundary, such that it is convenient to leave the original crack in place. In this case, it must be demonstrated that the crack and any potential future growth of the crack does not impact the structural integrity of the vessel.

This calculation presents the results of an ASME Code Section XI Appendix A flaw evaluation for such cracks. This evaluation postulates a double-sided crack that has propagated through the J-Weld and is beginning to encroach on the carbon steel material that comprises the pressure boundary. The assumed flaw configuration is evaluated to determine its growth rate and stability for plant operation in order to demonstrate structural integrity of the pressure boundary for the remaining life of the plant.

2.0 Summary of Results and Conclusions

Information for Sections 2.0 – 2.3 is proprietary to Westinghouse Electric.

3.0 Assumptions and Open Items

Information for Sections 3.0 – 3.2 is proprietary to Westinghouse Electric.

4.0 Acceptance Criteria

Information for Section 4.0 is proprietary to Westinghouse Electric.

5.0 Computer Codes Used In Calculation

Information for Section 5.0 is proprietary to Westinghouse Electric.

6.0 Calculations

Information for Sections 6.0 – 6.3 is proprietary to Westinghouse Electric.

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