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MEMORANDUM TO: Timothy Kobitz
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Advisory Committee on Reactor Safeguards (ACRS)

FROM: Noel F. Dudley
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SUBJECT: ACRS REVIEW OF THE ST. LUCIE, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION (TAC NOS. MB3404 AND MB3409)

The purpose of this memorandum is to forward information to the ACRS concerning its review of the St. Lucie, Units 1 and 2, license renewal application. Attached are a hard copy of the license renewal application; a CD rom containing the license renewal application and the Updated Final Safety Analysis Reports (UFSARs) for St. Lucie, Units 1 and 2; and selected applicant responses to the staff's requests for additional information (RAIs).

The license renewal application provides the basis for Florida Power and Light Company's request for renewing the operating licenses for St. Lucie, Units 1 and 2, for an additional 20 years. The UFSARs form part of the current licensing basis, which is used during the license renewal scoping and screening process.

The applicant's responses to the staff's RAIs provide information that the staff used to reach its adequate assurance findings. Some of these responses identify additional structures or components that are added to the scope of license renewal and the required aging management reviews. Other responses contain additional technical information. One of the responses identifies a new aging management program. The attached responses are relate to the following license renewal application sections and the associated RAI issues.

Section 2.1 Scoping and Screening Methodology

RAI 2.2-1 Non-safety-related systems, structures, and components of which failure could prevent satisfactory accomplishment of safety-related functions (pp. 1-14)

RAI 2.2-2 Non-safety-related systems and structured relied on for compliance with the station blackout rule (pp. 15-25)

Containments

Pipe Whip/Jet Impingement/Physical Contact – There is no non safety-related high energy piping inside the Containments. All high energy piping is safety-related and thus within the scope of license renewal.

Leakage/Spray – Safety-related components inside the Containments are designed to accommodate the effects of leakage and spray, without loss of function, regardless of the source.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Component Cooling Water Areas

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping in the Component Cooling Water Areas.

Leakage/Spray – For St. Lucie Unit 1, this is an outdoor area. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted by leakage or spray. For St. Lucie Unit 2, although this area is an indoor area, safety-related components are also designed for outdoor service and as a result would not be impacted from leakage or spray.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Condensate Storage Tank Enclosures

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping in the Condensate Storage Tank Enclosures.

Leakage/Spray – For St. Lucie Unit 1, this is an outdoor area. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray. For St. Lucie Unit 2, although this area is an indoor area, safety-related components are also designed for outdoor service and as a result would not be impacted from leakage or spray.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Diesel Oil Equipment Enclosures

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping in the Diesel Oil Equipment Enclosures.

Leakage/Spray – For St. Lucie Unit 1, this is an outdoor area. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray. For St. Lucie Unit 2, although this area is an indoor area, safety-related components are also designed for outdoor service and as a result would not be impacted from leakage or spray. Additionally, the non safety-related piping in this area is normally isolated.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Emergency Diesel Generator Buildings

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping in the Emergency Diesel Generator Buildings.

Leakage/Spray – The Emergency Diesel Generator Buildings contain small bore, stainless steel, non safety-related Demineralized Makeup Water piping and associated components that could potentially affect safety-related electrical components if failures are assumed.

Results – The Unit 1 Demineralized Makeup Water piping and associated components above have been included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(2). (Note that the Unit 2 Demineralized Makeup Water piping and associated components were already included in the scope of license renewal because these components were designed to seismic Category I requirements to address the potential for interaction with safety-related components, and thus were determined to meet the scoping criteria of 10 CFR 54.4(a)(2). See LRA Subsection 2.3.3.3, Section 3.3, and Table 3.3-3.) An AMR evaluation of the Unit 1 Demineralized Makeup Water piping and associated components based on AMRs performed on stainless steel components exposed to the same internal and external environments yields the results presented below.

TABLE 2.1-1
COMPONENTS MEETING 10 CFR 54.4(a)(2)
IN THE EMERGENCY DIESEL GENERATOR BUILDINGS

Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Internal Environment					
Piping/fittings Valves (Unit 1 Demineralized Makeup Water)	Pressure boundary	Stainless steel	Treated water – other	Loss of material	Chemistry Control Program
External Environment					
Piping/fittings Valves (Unit 1 Demineralized Makeup Water)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required

Fuel Handling Buildings

Pipe Whip/Jet Impingement/Physical Contact – There is no in-service high energy piping in the Fuel Handling Buildings.

Leakage/Spray – There is no in-service non safety-related piping containing fluid and/or steam in rooms where leakage or spray could effect safety-related electrical components.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Intake Structures

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping in the Intake Structures.

Leakage/Spray – These are outdoor areas. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Reactor Auxiliary Buildings

Pipe Whip/Jet Impingement/Physical Contact – All non safety-related high energy piping inside the Reactor Auxiliary Buildings is already within the scope of license renewal. Note that Auxiliary Steam to the Reactor Auxiliary Buildings is normally isolated by valves located in the Turbine Buildings.

Leakage/Spray – The Reactor Auxiliary Buildings contain non safety-related piping and associated components that could potentially affect safety-related electrical components if arbitrary failures are assumed. The specific piping is as follows:

- Small bore, stainless steel, Chemical and Volume Control piping and associated components in the AB switchgear rooms (Units 1 and 2).
- Carbon steel, Component Cooling Water piping and associated components in the mechanical penetration rooms (Units 1 and 2) and AB switchgear room (Unit 1 only).
- Small bore, stainless steel, Demineralized Makeup Water piping and associated components in the AB switchgear rooms (Units 1 and 2).
- Small bore, stainless steel, Primary Makeup Water piping and associated components in the mechanical penetration room (Unit 1 only). (Note that the non safety-related Primary Makeup Water piping and associated components in the Unit 2 mechanical penetration room were already included in the scope of license renewal because these components are relied on during postulated fires, and thus were determined to meet the scoping criteria of 10 CFR 54.4(a)(3). See LRA Subsection 2.3.3.11, Section 3.3, and Table 3.3-11.)
- Small bore, stainless steel, Sampling piping and associated components in the mechanical penetration rooms (Units 1 and 2).
- Small bore, galvanized carbon steel, Service Water piping and associated components in the ventilation equipment rooms (Units 1 and 2) and a small portion of the -0.5 foot elevation hallway (Unit 2 only). (Note that the stainless steel Service Water piping and associated components in the Units 1 and 2 battery rooms were already included in the scope of license renewal because these components were designed to seismic Category I requirements for the potential of interaction, and thus were determined to meet the scoping criteria of 10 CFR 54.4(a)(2). See LRA Subsection 2.3.3.13, Section 3.3, and Table 3.3-13)
- Small bore, stainless steel, Waste Management piping and associated components in the mechanical penetration rooms (Units 1 and 2).

Results – The piping and associated components noted above have been included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(2). An AMR evaluation of these components based on AMRs of components of the same materials exposed to the same internal and external environments yields the results presented below.

TABLE 2.1-2
COMPONENTS MEETING 10 CFR 54.4(a)(2)
IN THE REACTOR AUXILIARY BUILDINGS

Component/Commodity Grouping	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Internal Environment					
Piping/fittings Valves (Chemical and Volume Control – AB switchgear rooms)	Pressure boundary	Stainless steel	Treated water – borated	Loss of material	Chemistry Control Program
Piping/fittings Valves (Component Cooling Water – mechanical penetration rooms and Unit 1 AB switchgear room)	Pressure boundary	Carbon steel	Treated water – other	Loss of material	Chemistry Control Program
Piping/fittings Valves (Demineralized Makeup Water – AB switchgear rooms)	Pressure boundary	Stainless steel	Treated water – other	Loss of material	Chemistry Control Program
Piping/fittings Valves (Primary Makeup Water – Unit 1 mechanical penetration room)	Pressure boundary	Stainless steel	Treated water – other	Loss of material	Chemistry Control Program
Piping/fittings Valves (Sampling – mechanical penetration rooms)	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program
Piping/fittings Valves (Service Water – ventilation equipment rooms and a small portion of the Unit 2 -0.5 ft. elevation hallway)	Pressure boundary	Galvanized carbon steel	Raw water – city water	Loss of material	Systems and Structures Monitoring Program
Piping/fittings Valves (Waste Management – mechanical penetration rooms)	Pressure boundary	Stainless steel	Raw water – drains	None	None required

NOTES:

1. Portions of the system >140°F are potentially susceptible to SCC (see LRA Appendix C).

**TABLE 2.1-2 (continued)
COMPONENTS MEETING 10 CFR 54.4(a)(2)
IN THE REACTOR AUXILIARY BUILDINGS**

Component/Commodity Grouping	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
External Environment					
Piping/fittings Valves (Chemical and Volume Control - AB switchgear rooms)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required
Piping/fittings Valves (Component Cooling Water – mechanical penetration rooms and Unit 1 AB switchgear room)	Pressure boundary	Carbon steel	Indoor – not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Piping/fittings Valves (Demineralized Makeup Water - AB switchgear rooms)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required
Piping/fittings Valves (Primary Makeup Water - Unit 1 mechanical penetration room)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required
Piping/fittings Valves (Sampling - mechanical penetration rooms)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required
Piping/fittings Valves (Service Water - ventilation equipment rooms and a small portion of the Unit 2 -0.5 ft. elevation hallway)	Pressure boundary	Galvanized carbon steel	Indoor – not air conditioned	None (Note: no borated water sources in the area)	None required
Piping/fittings Valves (Waste Management - mechanical penetration rooms)	Pressure boundary	Stainless steel	Indoor – not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

Steam Trestle Areas

Pipe Whip/Jet Impingement/Physical Contact – All high energy piping within the Steam Trestle Areas is located outdoors. Additionally, non safety-related high energy piping in these areas is within the scope of license renewal because it meets other scoping criteria of 10 CFR 54.4(a).

Leakage/Spray – These are outdoor areas. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Turbine Building (Unit 1 only)

Pipe Whip/Jet Impingement/Physical Contact – All high energy piping within the Unit 1 Turbine Building is located outdoors. Additionally, significant portions of the non safety-related Main Steam and Turbine piping and associated components are within the scope of license renewal because they meet other scoping criteria of 10 CFR 54.4(a). (See License Renewal Boundary Drawings 1-MS-01, 1-MS-02, and 1-MS-03.) Other non safety-related high energy piping in the Unit 1 Turbine Building includes portions of the Main Feedwater, Auxiliary Steam, Condensate, Condensate Polishing, Extraction Steam, and Heater Drains and Vents systems. Review of these systems concluded that only piping segments of the Main Feedwater, Condensate, and Heater Drains and Vents systems could potentially affect the safety-related motor operated feedwater isolation valves and associated cable and conduit if failures are assumed.

Leakage/Spray – This is essentially an outdoor area. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray.

Results – The segments of the Main Feedwater, Auxiliary Feedwater and Condensate, and Heater Drains and Vents system piping and associated components noted above have been included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(2). An AMR evaluation of these components based on AMRs performed on carbon steel components exposed to the same internal and external environments yields the results presented below.

TABLE 2.1-3
COMPONENTS MEETING 10 CFR 54.4(a)(2)
IN THE TURBINE BUILDING (UNIT 1 ONLY)

Component/Commodity Grouping	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Internal Environment					
Piping/fittings Valves (Main Feedwater in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Treated water – Secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Piping/fittings Valves (Auxiliary Feedwater and Condensate in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Treated water – Secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program[2]
Piping/fittings Valves (Heater Drains and Vents in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Treated water – Secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
External Environment					
Piping/fittings Valves (Main Feedwater in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Outdoor	None[1]	None required
Piping/fittings Valves (Auxiliary Feedwater and Condensate in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Outdoor	None[1] Loss of material[3]	None required Systems and Structures Monitoring Program
Piping/fittings Valves (Heater Drains and Vents in the area of the feedwater isolation valves and associated cable and conduit[4])	Pressure Boundary	Carbon Steel	Outdoor	None[1]	None required

NOTES:

1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material (see LRA Appendix C).

2. Condensate System components exposed to temperatures greater than 200°F only.
3. Condensate System components that operate at temperatures less than 212°F only.
4. License renewal boundaries are identified on St. Lucie Piping and Instrumentation Diagrams (P&IDs) and are available on-site for review.

Ultimate Heat Sink Dam

Pipe Whip/Jet Impingement/Physical Contact – There is no high energy piping at the Ultimate Heat Sink Dam.

Leakage/Spray – There is no non safety-related piping containing fluid or steam in this area. Additionally, all safety-related components are designed for outdoor service and as a result would not be impacted from leakage or spray.

Results – No additional non safety-related piping is required to be included within the scope of license renewal.

Yard Structures

Pipe Whip/Jet Impingement/Physical Contact – The high energy piping within Yard Structures is located outdoors between the Steam Trestle Areas and the Turbine Buildings (Main Steam and Main Feedwater), and on the west side of the Turbine Buildings (Condensate Polishing and portions of Unit 1 Condensate). Assumed failures of piping associated with Unit 2 Main Steam, Unit 2 Main Feedwater, and Unit 1 Condensate and Condensate Polishing will not impact safety-related components based on their location. Additionally, the Unit 1 non safety-related Main Steam piping and associated components in this area are within the scope of license renewal because they meet other scoping criteria of 10 CFR 54.4(a). (See License Renewal Boundary Drawings 1-MS-01, 1-MS-02, and 1-MS-03.) However, piping segments of Unit 1 Main Feedwater could potentially affect safety-related cable and conduit if failures are assumed.

Leakage/Spray – This is an outdoor area. All safety-related electrical components installed outdoors are designed for a salt laden atmosphere, hurricane winds of 194 mph, tornado winds of 360 mph, and torrential rains. Outdoor safety-related motors are rated for outdoor service, weather proof, and typically built to ANSI/NEMA MG-1 standards. Outdoor safety-related junction boxes, termination boxes, and boxes which house electrical devices are also rated for outdoor service and built to NEMA 4 standards. As a result, safety-related component functions would not be impacted from leakage or spray.

Results – The segments of Unit 1 Main Feedwater system piping and associated components noted above have been included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(2). An AMR evaluation of these components based on AMRs performed on carbon steel components exposed to the same internal and external environments yields the results presented below.

TABLE 2.1-4
COMPONENTS MEETING 10 CFR 54.4(a)(2)
IN YARD STRUCTURES

Component/ Commodity Grouping	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Internal Environment					
Piping/fittings (Unit 1 Main Feedwater between the Steam Trestle and the Turbine Building)	Pressure boundary	Carbon steel	Treated water – secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
External Environment					
Piping/fittings (Unit 1 Main Feedwater between the Steam Trestle and the Turbine Building)	Pressure boundary	Carbon steel	Outdoor	None[1]	None required

NOTE

1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material (see LRA Appendix C).

Conclusion

Based on the above evaluation performed consistent with the guidance of the March 15, 2002 NRC letter regarding 10 CFR 54.4(a)(2) scoping:

- The Unit 1 Heater Drains and Vents and Unit 1 Demineralized Makeup Water systems are identified as within the scope of license renewal,
- Additional piping and components associated with the following in-scope systems are identified as in the scope of license renewal:
  - Unit 1 only – Primary Makeup Water, Main Feedwater, and Auxiliary Feedwater and Condensate
  - Unit 2 only – Demineralized Makeup Water
  - Units 1 and 2 – Chemical and Volume Control, Component Cooling Water, Sampling, Service Water, and Waste Management
- The Boric Acid Wastage Surveillance Program, the Chemistry Control Program, the Flow Accelerated Corrosion Program, and the Systems and Structures Monitoring Program have been revised to include the components as noted in Tables 2.1-1, 2.1-2, 2.1-3, and 2.1-4 above.

RAI 2.1 - 2

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

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

FPL Response

Specific references regarding the Station Blackout (SBO) Current Licensing Basis (CLB) for St. Lucie include Unit 1 UFSAR Section 15.2.13 and Unit 2 UFSAR Section 15.10, and references 2.1-21, 2.1-22, 2.1-23, 2.1-24, and 2.1-25 listed in Subsection 2.1.5 (page 2.1-18) of the St. Lucie License Renewal Application (LRA). Based on these references, SBO scoping for the St. Lucie LRA did not identify restoration of offsite power to be relied on or required under the SBO CLB for St. Lucie. Systems relied on for restoration of onsite power, however, were included in the scope of license renewal. In addition to the Emergency Diesel Generators, electrical systems identified as within the scope of license renewal for SBO included 480 V Electrical, 120/208 V Electrical, 120 V Vital AC, 125 V DC, 4.16 kV Electrical, Communications, Reactor Protection, Containment Electrical Penetrations, Safeguards Panels, and the Data Acquisition Remote Terminal Unit.

FPL contends that restoration of offsite power is not relied on to meet the requirements of the SBO Rule for St. Lucie. However, based on the NRC guidance provided in the April 1, 2002 letter and RAI 2.1-2, FPL has performed an evaluation to determine the additional electrical and structural components that are in the scope of license renewal for restoration of offsite power at St. Lucie. For those electrical and structural components determined to be within the scope of license renewal and requiring an aging management review (AMR), an AMR evaluation was performed. The results of this evaluation are presented below.

Electrical Components

Consistent with the NRC position, the additional electrical components included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(3) for restoration of offsite power are as follows:

1. Circuit breakers and switches to connect the Startup Transformer circuits to the grid
2. Batteries and DC controls associated with the Startup Transformer circuit breakers
3. Startup Transformers
4. Non safety-related 4.16 kV switchgear

5. DC control and power (lead sheath) cables
6. All Aluminum Alloy Conductor (Type AAAC) transmission conductors between the Startup Transformers and circuit breakers
7. High voltage insulators associated with the transmission conductors
8. Switchyard bus and connections between the Startup Transformers and circuit breakers
9. Nonsegregated-phase bus between the Startup Transformers and the non safety-related 4.16 kV switchgear

Based on the guidance in NEI 95-10, the circuit breakers, switches, batteries, DC controls, Startup Transformers, and the non safety-related 4.16 kV switchgear do not require an aging management review because they are considered active components. The DC control cable and power cable (lead sheath) insulation types were previously evaluated in the AMRs summarized in Section 3.6 of the LRA. An AMR evaluation of the remaining electrical components is presented below.

Type AAAC Transmission Conductors

The Type AAAC transmission conductors at St. Lucie are constructed of an aluminum core and strand.

The aging effects for transmission conductors requiring evaluation are loss of conductor strength and those associated with vibration. The most prevalent mechanism contributing to loss of conductor strength of transmission conductor is corrosion. Corrosion is not an aging mechanism of concern for Type AAAC transmission conductors, because they are constructed entirely of aluminum which is resistant to corrosion.

Further, the National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. The St. Lucie Units 1 and 2 conductors are 1081 MCM Type AAAC and they are designed and installed in accordance with NESC.

Tests performed by Ontario Hydroelectric showed a 30% loss of composite conductor strength of an 80-year-old transmission conductor. Assuming a 30% loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength.

Based on the above, loss of conductor strength of the St. Lucie Units 1 and 2 Type AAAC transmission conductors is not an aging effect requiring management for the period of extended operation. This is further supported by the fact that FPL has been installing and maintaining transmission conductors on its transmission system for more than 60 years and has not had to replace any conductors due to aging problems.

Transmission conductor vibration would be caused by wind loading. Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation. Thus, loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not aging effects requiring management for the period of extended operation for St. Lucie Units 1 and 2.

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to transmission conductors.

St. Lucie Units 1 and 2 operating experience was also reviewed to validate aging effects for transmission conductors. This review included non-conformance reports, license event reports, and condition reports for any documented instances of transmission conductor aging, in addition to interviews with responsible transmission engineering personnel. No unique aging effects were identified from this review beyond those discussed above.

High Voltage Insulators

High voltage insulators are constructed of the following materials:

- porcelain
- cement
- aluminum

Aging effects for high voltage insulators requiring evaluation are surface contamination and loss of material.

Various airborne materials such as dust, salt and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. This has been confirmed by St. Lucie operating experience.

Therefore, surface contamination of the St. Lucie Units 1 and 2 high voltage insulators is not an aging effect requiring management for the period of extended operation.

Loss of material due to mechanical wear is an aging effect for strain and suspension insulators if they are subject to significant movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swinging is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, industry experience has shown that transmission conductors do not normally swing and that when they do, due to a substantial wind, do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspections of the St. Lucie Units 1 and 2 high voltage insulators. Therefore, loss of material due to wear of the St. Lucie Units 1 and 2 high voltage insulators is not an aging effect requiring management for the period of extended operation.

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to transmission insulators.

The following document related to insulators was identified in this review:

- IN 93-95, Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators

High voltage insulators at St. Lucie are washed and coated with silicon to prevent salt buildup. As a result of this, no unique aging effects were identified in the above documents beyond those discussed in this section.

St. Lucie Units 1 and 2 operating experience was also reviewed to validate aging effects for transmission insulators. This review included non-conformance reports, license event reports, and condition reports for any documented instances of transmission insulator aging, in addition to interviews with responsible transmission engineering personnel. No unique aging effects were identified from this review beyond those identified above.

Switchyard Buses and Connections

The switchyard buses and connections are constructed of the following materials:

- aluminum
- bronze
- copper

Aging effects for the switchyard buses and connections requiring evaluation are those associated with vibration.

The switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components such as cement footings and structural steel. With no connections to moving or vibrating equipment, vibration is not an applicable stressor for the switchyard buses and connections and aging effects due to vibration are not applicable. This has been confirmed by St. Lucie operating experience. Therefore, aging effects due to vibration of the St. Lucie Units 1 and 2 switchyard buses and connections do not require management for the period of extended operation.

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to switchyard buses and connections. No documents involving switchyard buses and connections were identified.

St. Lucie Units 1 and 2 operating experience was also reviewed to validate aging effects for switchyard buses and connections. This review included non-conformance reports, license event reports, and condition reports for any documented instances of switchyard bus and connection aging, in addition to interviews with responsible transmission engineering personnel. No unique aging effects were identified from this review beyond those discussed above.

Nonsegregated-Phase Bus

The nonsegregated-phase buses are constructed of the following materials:

- silicone caulk
- aluminum
- bronze
- copper
- galvanized metals
- stainless steel
- porcelain

Aging effects for the nonsegregated-phase buses requiring evaluation are those associated with temperature, precipitation, and vibration.

The only material above requiring evaluation with regard to aging effects associated with temperature is silicone caulk. The silicone caulk used in the nonsegregated-phase buses is Dow Corning Silastic 3110, which is a white, room temperature vulcanizing (RTV), silicone rubber encapsulant. It is rated as having a useful upper temperature of 200°C (392°F). Dow Corning cannot provide Arrhenius data for this specific RTV encapsulant; however, it is silicone rubber and its use temperature is consistent with other silicone rubbers which would imply the following thermal life data:

- 273°F (133.9°C) service temperature = 60-year life maximum temperature
- 176.0°F (80.0°C) continuous design service temperature (ambient 104°F plus self heating) of the nonsegregated-phase buses = life much greater than 60 years

The 60-year life maximum temperature is much greater than the design service temperature of the silicone caulk. Therefore, there are no aging effects requiring management for silicone caulk for the extended period of operation.

The only materials in the above list requiring evaluation with regard to aging effects associated precipitation are galvanized metals. Galvanized metals (bolts, washers, nuts and clamp screws) exposed to outside weather and precipitation are factory coated to inhibit corrosion. After more than 26 years in its service environment, loss of material due to corrosion has not been observed. Therefore, loss of material for galvanized metals associated with the nonsegregated-phase buses is not an aging effect requiring management.

The nonsegregated-phase buses are connected to static equipment that does not normally vibrate such as switchgear, transformers and disconnect switches. The nonsegregated-phase buses are supported by static structural components such as cement footings and building steel. Vibration is not an applicable stressor for these connections to non-moving and non-vibrating equipment and supports. Therefore, aging effects due to vibration do not require management.

In order to validate aging effects considered and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to nonsegregated-phase buses. The following documents related to nonsegregated-phase buses were identified in this review:

- Bulletin 79-27, Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation
- Generic Letter 91-11, Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrument Buses," and 49, "Interlocks and LCOs for Class 1E Tie Breakers" Pursuant to 10 CFR 50.54(f)
- IN 86-87, Loss of Offsite Power Upon an Automatic Bus Transfer
- IN 86-100, Loss of Offsite Power to Vital-Buses at Salem 2
- IN 88-55, Potential Problems Caused by Single Failure of an Engineered Safety Feature Swing Bus
- IN 89-64, Electrical Bus Bar Failures
- IN 91-57, Operational Experience on Bus Transfers
- IN 92-09, Overloading and Subsequent Lock Out of Electrical Buses During Accident Conditions
- IN 92-40, Inadequate Testing of Emergency Bus Undervoltage Logic Circuitry
- IN 93-28, Failure to Consider Loss of DC Bus in the Emergency Core Cooling System Evaluation May Lead to Nonconservative Analysis

No unique aging effects were identified in the above documents beyond those discussed in this section.

St Lucie operating experience was also reviewed to validate aging effects for the nonsegregated-phase buses. This review included non-conformance reports, license event reports, and condition reports for any documented instances of nonsegregated-phase bus aging, in addition to interviews with responsible engineering personnel. No unique aging effects were identified from this review beyond those discussed above.

Based on the discussions above, the AMR results for electrical components required for restoration of offsite power are as follows:

TABLE 2.1-5
ADDITIONAL ELECTRICAL COMPONENTS REQUIRED FOR RESTORATION OF OFFSITE POWER FOR SBO

Component	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Transmission conductors	To electrically connect specified sections of an electrical circuit to deliver voltage, current, or signal	All Aluminum Alloy Conductor (Type AAAC)	Outdoor	None	None required
Nonsegregated-phase buses Switchyard buses and connections	To electrically connect specified sections of an electrical circuit to deliver voltage, current, or signal	Aluminum Bronze Copper Galvanized metals Stainless steel Silicone caulk Porcelain	Outdoor	None	None required
High voltage insulators	To electrically isolate and provide structural support to transmission conductors	Aluminum Cement Porcelain	Outdoor	None	None required

Based upon the AMR results, and a review of industry information, NRC generic communications, and St. Lucie operating experience, there are no aging effects requiring management for transmission conductors, nonsegregated-phase buses, switchyard buses, connections, and high voltage insulators for the extended period of operation.

Structural Components

Consistent with the NRC position, the additional structural components included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(3) for restoration of offsite power are as follows:

1. Switchyard
    - Startup Transformer circuit breaker foundations
    - Covered cable trenches
    - Electrical component supports
    - Switchyard control building
    - DC electrical enclosures
    - Cable trays
    - Startup Transformer circuit breaker electrical enclosures
    - Transmission towers
    - Transmission tower foundations
2. Turbine Buildings
    - Switchgear rooms
    - Switchgear enclosures
    - Switchgear supports
    - Nonsegregated-phase bus supports
3. Yard Structures
    - Transmission towers
    - Nonsegregated-phase bus supports
    - Nonsegregated-phase bus foundations
    - Startup Transformer foundations
    - 4.16 kV Switchgear foundations
    - Transmission tower foundations
    - Electrical duct banks and manholes already included in LRA Table 3.5-16 (page 3.5-93)

An AMR evaluation of these components based on AMRs of St. Lucie structural components of the same materials exposed to the same environments yields the results presented below in three tables (one for each structure).

TABLE 2.1-6
SWITCHYARD ADDITIONAL STRUCTURAL COMPONENTS REQUIRED FOR RESTORATION OF OFFSITE POWER FOR SBO

Component	Intended Function[2]	Material	Environment	Aging Effects Requiring Management	Program/Activity
Startup Transformer circuit breaker foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
Covered cable trenches	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
Electrical component supports	10	Carbon steel	Indoor – air conditioned	None	None required
			Outdoor	Loss of material	Systems and Structures Monitoring Program
Switchyard control building	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
		Masonry (unreinforced)	Outdoor	Cracking	Systems and Structures Monitoring Program
		Weatherproofing	Outdoor	Loss of seal	Systems and Structures Monitoring Program
DC electrical enclosures	10	Carbon steel	Indoor – air conditioned	None	None required
Cable trays	10	Aluminum	Indoor – air conditioned	None	None required
Startup Transformer circuit breaker electrical enclosures	10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Transmission towers	10	Galvanized carbon steel	Outdoor	None	None required
Transmission tower foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program

NOTES

1. The aging management reviews performed by FPL on above groundwater reinforced concrete did not identify any aging effects requiring management, however based on the NRC Staff position, FPL will inspect accessible surfaces of above groundwater reinforced concrete structures and structural components for concrete degradation.

2. Intended Function 10 is defined in LRA Table 3.5-1 (page 3.5-34) as follows, "Provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events. (NOTE: Although not credited in the analyses for these events, these components have been conservatively included in the scope of license renewal.)"

TABLE 2.1-7
TURBINE BUILDING ADDITIONAL STRUCTURAL COMPONENTS REQUIRED FOR RESTORATION OF OFFSITE POWER FOR SBO

Component	Intended Function[2]	Material	Environment	Aging Effects Requiring Management	Program/Activity
Switchgear rooms	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
		Masonry (unreinforced)	Outdoor	Cracking	Systems and Structures Monitoring Program
		Weatherproofing	Outdoor	Loss of seal	Systems and Structures Monitoring Program
Switchgear enclosures	10	Carbon steel	Indoor – not air conditioned	Loss of material	Systems and Structures Monitoring Program
Switchgear supports	10	Carbon steel	Indoor – not air conditioned	Loss of material	Systems and Structures Monitoring Program
Nonsegregated phase bus supports	10	Carbon steel	Indoor – not air conditioned	Loss of material	Systems and Structures Monitoring Program

NOTES

1. The aging management reviews performed by FPL on above groundwater reinforced concrete did not identify any aging effects requiring management, however based on the NRC Staff position, FPL will inspect accessible surfaces of above groundwater reinforced concrete structures and structural components for concrete degradation.
2. Intended Function 10 is defined in LRA Table 3.5-1 (page 3.5-34) as follows, "Provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events. (NOTE: Although not credited in the analyses for these events, these components have been conservatively included in the scope of license renewal.)"

TABLE 2.1-8
YARD STRUCTURES ADDITIONAL STRUCTURAL COMPONENTS REQUIRED FOR RESTORATION OF OFFSITE POWER FOR SBO

Component	Intended Function[2]	Material	Environment	Aging Effects Requiring Management	Program/Activity
Transmission towers	10	Galvanized carbon steel	Outdoor	None	None required
Nonsegregated phase bus supports	10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Nonsegregated phase bus foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
Startup Transformer foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
4.16 kV switchgear foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program
Transmission tower foundations	10	Concrete	Outdoor	Concrete degradation[1]	Systems and Structures Monitoring Program

NOTES

1. The aging management reviews performed by FPL on above groundwater reinforced concrete did not identify any aging effects requiring management, however based on the NRC Staff position, FPL will inspect accessible surfaces of above groundwater reinforced concrete structures and structural components for concrete degradation.
2. Intended Function 10 is defined in LRA Table 3.5-1 (page 3.5-34) as follows, "Provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events. (NOTE: Although not credited in the analyses for these events, these components have been conservatively included in the scope of license renewal.)"

Conclusion

Based on the evaluation performed consistent with the guidance of the NRC letter of April 1, 2002 regarding scoping for SBO for license renewal:

- For systems, the Units 1 and 2 Generation and Distribution systems and additional components in the in-scope Units 1 and 2 4.16 kV Electrical and DC Electrical systems are identified as within the scope of license renewal.
- For structures, the Switchyard and additional structural components in the in-scope Units 1 and 2 Turbine Buildings and Yard Structures are identified as within the scope of license renewal.
- The Systems and Structures Monitoring Program has been revised to include the components as noted in Tables 2.1-6, 2.1-7 and 2.1-8 above.

RAI 2.3.1 - 2

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

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

FPL Response

Thermal sleeves are included in the design of the pressurizer surge and spray nozzles and are designed to protect these nozzles from thermal shock. Since the thermal sleeves are not part of the nozzle pressure boundary, their failure would not affect the nozzles pressure boundary intended function. However, the thermal sleeves are included in the fatigue analyses of the pressurizer surge and spray nozzles and these analyses have been identified as a time-limited aging analysis (TLAA) and dispositioned in LRA Subsection 4.3.1 (page 4.3-2). Accordingly, the thermal sleeves are considered to be within the scope of license renewal, pursuant to 10 CFR 54.4(a)(2) and require an aging management review.

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 and are exposed to an environment of treated water – primary. The only aging effect requiring evaluation for the thermal sleeves is cracking. Cracking due to stress corrosion or primary stress corrosion was determined not to be an aging effect requiring management based on the relatively low stress applied to the thermal sleeves. As mentioned above, cracking due to fatigue has been identified as a TLAA and is addressed analytically in LRA Subsection 4.3.1. Accordingly, there are no aging effects requiring management for the thermal sleeves.

Note that this conclusion is consistent with that included NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (LRA Reference 3.1-1). Pressurizer thermal sleeves are included in Chapter IV of the GALL Report, Item C2.5.5. As indicated in the GALL Report table, the aging effect/mechanism identified for the thermal sleeves is cumulative fatigue damage/fatigue. The GALL Report further states that fatigue is a TLAA for the period of extended operation and further refers to NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Section 4.3 "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1). No additional aging effects are identified in the GALL Report for pressurizer thermal sleeves.

Table 3.1-1 is revised as noted below.

TABLE 3.1-1
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
		Pressurizers			
		Internal Environment			
Surge nozzle thermal sleeves [IV C2.5.5] Spray nozzle thermal sleeves [IV C2.5.5]	Pressure boundary (Note 1)	Alloy 600	Treated water – primary	None	None required

Note: 1. The thermal sleeves are not part of the pressure boundary, but do provide thermal shielding to minimize nozzle low cycle thermal fatigue.

2.3.3.14 Turbine Cooling Water - Unit 1 only

RAI 2.3.3 - 13

On license renewal boundary drawing 1-TCW-01, the licensee indicates the components that are within the scope of license renewal. However, Table 3.3-14 of the LRA does not include all of these components. Justify why the following components are excluded from Table 3.3-14:

- Instrument air aftercoolers shown on license renewal boundary drawing 1-TCW-01 at locations A4, C4, and D4.
- Jackets for the service air compressor shown at location B4 on drawing 1-TCW-01
- Instrument air compressors 1A and 1B shown at locations B4 and D4 on drawing 1-TCW-01

If these components were included in Table 3.3-14 under the category of "piping/fittings," clarify why Table 3.3-14 does not list a heat transfer intended function for these components.

FPL Response

The instrument air compressor aftercoolers are addressed under Instrument Air and are listed in LRA Table 3.3-8 (pages 3.3-51, 3.3-52 and 3.3-56). The tube side ("Instrument air compressor cooler tubes" on page 3.3-51) includes both heat transfer and pressure boundary as intended functions.

Instrument air compressors 1A and 1B are in the scope of license renewal, but do not require an aging management review because they are active components in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10.

Instrument air and service air jacket coolers are also in the scope of license renewal but do not require aging management review. The coolers are an integral part of the air compressors and are therefore considered active components in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10.

Note that the service air compressor aftercooler was inadvertently omitted from LRA Table 3.3-14. The aftercooler for service air has no heat transfer requirements, but does perform a function of pressure boundary for Turbine Cooling Water. LRA Table.3.3-14 is revised as shown below:

LRA page 3.3-73 (Internal Environment)
LRA page 3.3-74 (External Environment)

TABLE 3.3-14
TURBINE COOLING WATER (UNIT 1 ONLY)

Component/ Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Service air compressor cooler tubes	Pressure boundary	Copper	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Service air compressor cooler shell	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
External Environment					
Service air compressor cooler shell	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program

RAI 2.3.3 - 15

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.

FPL Response

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 3.3 - 3

In Table 3.3-5, "Emergency Cooling Canal," and Table 3.3-9, "Intake Cooling Water," please clarify the environment to which the concrete with embedded/encased carbon steel piping/fitting is exposed. In particular, state whether that environment is raw water-salt water, outdoor air, or some other(s).

The raw water-salt water environment contains chlorides. Similarly, the outdoor environment of St. Lucie is defined in the LRA as moist, salt-laden atmospheric air, with temperatures of 27°F – 93°F, 73% average humidity, and exposure to weather, including precipitation and wind. Therefore, the outdoor environment also contains chlorides. These chlorides in the moist, salt-laden atmospheric air may reach the steel/concrete interface in the interior of the concrete through the process of permeation, infiltration, and condensation through the pores of the concrete. Accumulation of high enough levels of chlorides will result in attacks on and disruption of the protective film formed on the surfaces of the steel as a result of the originally high pH levels in the concrete environment. Once some particular region of the protective film is destroyed, localized corrosion of the steel will begin through an electrochemical process. However, Tables 3.3-5 and 3.3-9 of the LRA do not identify any aging effects for carbon steel components in the emergency cooling canal system and the intake cooling water system associated with external exposure to an embedded/encased environment.

Explain why the aging process as described is not applicable to St. Lucie, and discuss the operating history of the plant to support the conclusion regarding the absence of applicable aging effects with respect to cracking and loss of materials.

FPL Response

With respect to the Emergency Cooling Canal embedded/encased piping listed on LRA Table 3.3-5 (page 3.3-41), this piping is actually bolted to the concrete and is therefore not embedded/encased. In addition, the piping/fittings and bolting shown on LRA Table 3.3-5 are made of aluminum bronze and not carbon steel. LRA Table 3.3-5 (page 3.3-41) is revised as follows:

TABLE 3.3-5
EMERGENCY COOLING CANAL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Internal Environment					
Piping/fittings	Pressure boundary	Aluminum bronze	Raw water – salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
External Environment					
Piping/fittings	Pressure boundary	Aluminum bronze	Raw water – salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Bolting (mechanical closures)	Pressure boundary	Aluminum bronze	Raw water – salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

With respect to the Intake Cooling Water (ICW) embedded/encased piping listed on LRA Table 3.3-9 (page 3.3-63), the piping is embedded/encased in concrete where it passes through the walls of the St. Lucie Units 1 and 2 Component Cooling Water Areas. The external environments are outdoor (Unit 1) and indoor – not air conditioned (Unit 2) inside the Component Cooling Water Areas and buried (both units) outside the areas. The review of the St. Lucie plant-specific operating experience identified that only concrete which is submerged or in a "splash zone" (subject to wetting, e.g., due to proximity to the intake or discharge), is susceptible to chloride intrusion. The Unit 1 & 2 embedded/encased ICW piping penetrates vertical concrete walls at elevated locations that are not submerged or located in splash zones. Therefore, chloride intrusion would not be expected to occur. If chloride intrusion and corrosion of the embedded/encased piping were to occur, rust bleeding at the concrete interface of the piping penetration would be visible. The review of St. Lucie plant-specific operating experience did not identify any degradation of the piping at this location. Therefore, no aging effects requiring management were specified for the embedded/encased ICW piping in this portion of the system. ICW piping at the plant discharge is exposed to an external environment of raw water – salt water (submerged). (See LRA Table 3.3-9 page 3.3-63.)

3.3.4 Diesel Generators And Support Systems

RAI 3.3.4 - 1

In Section 9.5.6.3, "System Evaluation," on page 9.5-12b of the Unit 2 updated Final Safety Analysis Report (UFSAR), the applicant states that the air receiver for the air-start system of the emergency diesel generator collects moisture to preclude fouling of the air-start valve with moisture and contamination. Provide justification for not identifying loss of material as an aging effect for the carbon steel, aluminum alloy, and copper alloy air-start system components that are exposed to the internal moist air environment.

FPL Response

LRA Table 3.3-4 (page 3.3-28) Air Start and Intake System incorrectly identified the internal environment for the Unit 2 Start-up air tanks (and associated valves, piping and fittings) as dry "Air/gas". Since the Unit 2 air start system does not have air dryers, the start-up air tanks and associated components are actually exposed to moist air. Although the material of these components is stainless steel and thus not subject to general corrosion, they are potentially susceptible to loss of material due to pitting corrosion.

As stated in the Unit 2 UFSAR Section 9.5.6.3, the air receiver for the air-start system of the emergency diesel generator collects moisture to preclude fouling of the air-start valve with moisture and contamination. These air tanks are periodically blown down to remove moisture. Therefore, Table 3.3-4 (page 3.3-28) has been corrected as shown below to indicate a "wetted air/gas" environment and credit the Periodic Surveillance and Preventive Maintenance Program. A review of St. Lucie plant-specific operating experience has not identified loss of material in the Unit 2 Air Start System.

Based upon moisture removal by periodic blow down of the start-up air tanks, the components downstream of the tanks are not subject to loss of material because the internal air/gas environment for these components is considered dry. All components downstream of the start-up air tanks are stainless steel or aluminum. There are no copper alloy or carbon steel components in the Unit 2 Air Start and Intake System.

Table 3.3-4 of the LRA (page 3.3-28) is revised as shown below:

TABLE 3.3-4
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/ Activity
Air Start and Intake System					
Internal Environment					
Start-up air tanks, drain piping and valves (Unit 2 only)	Pressure boundary	Stainless steel	Air/gas (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

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.

4.3 Metal Fatigue

RAI 4.3 - 1

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

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

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

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

FPL Response

Item 1

St. Lucie Unit 1 UFSAR Sections 3.9 and 5.2.1.2 and Unit 2 UFSAR Section 3.9 contain a listing of the design transients used in the design of the various Reactor Coolant System (RCS) Class 1 components. These design transients have been consolidated into Tables 4.3-1.1 and 4.3-1.2 for St. Lucie Units 1 and 2, respectively. However, each of these design transients is not necessarily a significant contributor to the overall Class 1 component fatigue usage. As part of license renewal, a comprehensive review of each RCS Class 1 component fatigue analysis was performed to determine which design transients are a significant contributor to overall fatigue usage. A design transient was deemed to be significant if the transient contributed greater than 0.1 to the overall component cumulative usage factor (CUF).

FPL has implemented a Fatigue Monitoring Program (LRA Appendix B Subsection 3.2.7 page B-37) at both St. Lucie Units 1 and 2 to fulfill plant Technical Specification requirements and to ensure that the significant "fatigue-sensitive" design transient counts are not exceeded during plant operation. A summary of the design transients included in the Fatigue Monitoring Program is provided in Tables 4.3-1.3 and 4.3-1.4 for St. Lucie Units 1 and 2, respectively. Note that some transients listed in these tables are not fatigue-sensitive, but they are included in the Fatigue Monitoring Program because of plant Technical Specification requirements. Also note that some fatigue-sensitive transients identified from the CUF screening process have been excluded from the Fatigue Monitoring Program due to large margins that are present with respect to actual cycle counts versus allowable cycle counts. For example, plant loading/unloading events are not monitored because the St. Lucie units are not load following plants, so these events rarely occur.

Cycle counting has been performed since the startup of each St. Lucie unit. This program counts the design transients identified in Tables 4.3-1.3 and 4.3-1.4 by recording the actual number and types of transients imposed on the RCS components, and ensures that the design transient limits are not exceeded. A review of plant operating records was performed to validate that the transient counts included in the Fatigue Monitoring Program are accurate. This review concluded that the program accurately identifies and classifies plant design transients and provides an effective and consistent method for categorizing, counting, and tracking design transients. The current number of operating cycles (as of December 31, 2000) for each transient included in the Fatigue Monitoring Program is included in Tables 4.3-1.3 and 4.3-1.4.

As part of license renewal, design basis transient severities were compared to the actual transients experienced at St. Lucie Units 1 and 2. This review was performed to demonstrate that the original design transient assumptions are severe enough to bound all operating events. Typical plant design transients were reviewed as part of the evaluation. The results of the review concluded that the original design transient assumptions are severe enough to bound all operating events.

Item 2

The number of operating cycles estimated for 60 years of plant operation is also shown in Tables 4.3-1.3 and 4.3-1.4 for St. Lucie Units 1 and 2, respectively. Conservative linear cycle projections based on the plant startup date were used for all events, except where noted in the "Comments" column in each table, as follows:

$$N_{60} = [\, N_{2000} / (2000 - Y_{startup}) \,] * (Y_{60} - Y_{startup})$$

where:	N_{60}	=	projected number of events for 60 years
	N_{2000}	=	number of events as of 12/31/2000
	$Y_{startup}$	=	year of plant startup
		=	1976 for St. Lucie Unit 1
		=	1982.67 for St. Lucie Unit 2
	Y_{60}	=	60th year of plant operation
		=	2036 for St. Lucie Unit 1
		=	2043 for St. Lucie Unit 2

This projection method is conservative in that it includes "learning curve" effects of early plant operation, as opposed to trends established by the most recent years of plant operation. The results provided in Tables 4.3-1.3 and 4.3-1.4 indicate that all transient projections remain well within the number of occurrences assumed in the design analyses for all events.

Item 3

The design transients listed in Tables 4.3-1.1 and 4.3-1.2 are a compilation of all RCS Class 1 design transients included in the St. Lucie Unit 1 and 2 UFSARs. A comparison of these transients with those being monitored by the Fatigue Monitoring Program (Tables 4.3-1.3 and 4.3-1.4) indicates that some of the UFSAR transients are not monitored by the program.

An explanation of this difference is provided in the response to Item 1 above. As discussed, the Fatigue Monitoring Program only tracks those design transients that are a significant contributor to the overall component CUF. As such, it is not necessary to track those design transients that are not a significant contributor to component fatigue.

Table 4.3-1.1
St. Lucie Unit 1 UFSAR Design Transients

Transient Description	Number of Cycles
Normal Conditions Transients:	
Plant Heatup	500
Plant Cooldown	500
Pressurizer Heatup	500
Pressurizer Cooldown	500
Plant Loading, 5%/min.	15,000
Plant Unloading, 5%/min.	15,000
10% Step Load Increase	2,000
10% Step Load Decrease	2,000
Normal Plant Variations, +/- 100 psi, +/- 6°F	10^6
Primary Coolant Pump Starting/Stopping	4,000
Purification	1,000
Low Volume Control and Makeup	2,000
Boric Acid Dilution	8,000
Cold Feed Following Hot Standby	15,000
Actuation of Main or Auxiliary Spray	500
Low Pressure Safety Injection, 40°F Water into 300°F Cold Leg	500
Opening of Safety Injection Return Line Valves	2,000
Initiation of Shutdown Cooling	500
Upset Condition Transients:	
Turbine Trip (Loss of Load)	40
Loss of Offsite Power (Loss of RCS Flow)	40
Reactor Trip	400
Inadvertent Auxiliary Spray Cycle	16
Loss of Charging Flow	200
Loss of Letdown Flow	50
Regenerative HX Isolation Long Term	80
Regenerative HX Isolation Short Term	40
Emergency Condition Transients:	
Loss of Secondary Pressure	5
Loss of Feedwater Flow	8
High Pressure Safety Injection, 40°F Water into 550°F Cold Leg	5

Table 4.3-1.1 (continued)
St. Lucie Unit 1 UFSAR Design Transients

Transient Description	Number of Cycles
Test Condition Transients:	
Primary System Hydrostatic Test, 3125 psia	10
Primary System Leak Test, 2250 psia	200
Secondary System Hydrostatic Test, 1250 psia	10
Secondary System Leak Test, 1000 psia	200

Table 4.3-1.2
St. Lucie Unit 2 UFSAR Design Transients

Transient Description	Number of Cycles
Normal Condition Transients:	
Plant Heatup	500
Plant Cooldown	500
Plant Loading, 5%/min.	15,000
Plant Unloading, 5%/min.	15,000
10% Step Load Increase	2,000
10% Step Load Decrease	2,000
Normal Plant Variations, +/- 100 psi, +/- 6°F	10^6
Purification and Boron Dilution	24,000
Upset Condition Transients:	
Turbine Trip (Loss of Load)	40
Loss of Offsite Power (Loss of RCS Flow)	40
Reactor Trip	400
Operating Basis Earthquake	200
Loss of Charging Flow	20
Loss of Letdown Flow	50
Isolation Check Valve Leaks	40
Emergency Condition Transients:	
Loss of Secondary Pressure	5
Test Condition Transients:	
Primary System Hydrostatic Test, 3125 psia	10
Primary System Leak Test, 2250 psia	200

Table 4.3-1.3
St. Lucie Unit 1 Design Transients Included in Fatigue Monitoring Program (FMP)

Transient	Design Cycles	Cycle Counts as of 12/31/00	60-Year Projection	Margin	Comments
Reactor Trip	400	46	115	71%	Fatigue-sensitive transient.
Plant Heatup	500	57	143	72%	Fatigue-sensitive transient.
Plant Cooldown	500	56	143	72%	Fatigue-sensitive transient.
Pressurizer Heatup	500	57	143	72%	Not a fatigue-sensitive transient, but included in FMP to be consistent with Unit 2.
Pressurizer Cooldown	500	56	143	72%	Not a fatigue-sensitive transient, but included in FMP to be consistent with Unit 2.
Primary Hydrostatic Test	10	1	3	75%	Fatigue-sensitive transient.
Secondary Hydrostatic Test	10	4	10	0%	Not a fatigue-sensitive transient, but included in Unit 1 Technical Specifications.
Primary Leak Test	200	45	113	44%	Not a fatigue-sensitive transient, but included in Unit 1 Technical Specifications.
Secondary Leak Test	200	1	3	99%	Not a fatigue-sensitive transient, but included in Unit 1 Technical Specifications.
Loss of Secondary Pressure	5	0	1	80%	Fatigue-sensitive transient. Assume 1 cycle occurs in 60-year life.
Pressurizer Spray	1,500	147	675	55%	Fatigue-sensitive transient (see Note 1).
Inadvertent Auxiliary Spray	16	3	8	53%	Not a fatigue-sensitive transient, but included in Unit 1 Technical Specifications.
Loss of Offsite Power (Loss of RCS Flow)	40	0	1	98%	Fatigue-sensitive transient. Assume 1 cycle occurs in 60-year life
Loss of Load	40	3	8	81%	Fatigue-sensitive transient.

Note: 1. Projection is based on recent cyclic trends versus linear projection. The number of cycles for this event was increased from the original number reported in the UFSAR based on additional plant-specific analysis of the pressurizer spray line.

Table 4.3-1.4
St. Lucie Unit 2 Design Transients Included in Fatigue Monitoring Program

Transient	Design Cycles	Cycle Counts as of 12/31/00	60-Year Projection	Margin	Comments
Reactor Trip	400	18	63	84%	Fatigue-sensitive transient. Assume 1 event/year since no additional events have occurred since 1996.
Plant Heatup	500	30	104	79%	Fatigue-sensitive transient.
Plant Cooldown	500	29	104	79%	Fatigue-sensitive transient.
Pressurizer Heatup	500	30	104	79%	Not a fatigue-sensitive transient, but included in Unit 2 Technical Specifications.
Pressurizer Cooldown	500	29	104	79%	Not a fatigue-sensitive transient, but included in Unit 2 Technical Specifications.
Primary Hydrostatic Test	10	1	3	65%	Not a fatigue-sensitive transient, but included in Unit 2 Technical Specifications.
Primary Leak Test	200	2	7	97%	Fatigue-sensitive transient.
Loss of Secondary Pressure	5	0	1	80%	Fatigue-sensitive transient. Assume 1 cycle occurs in 60-year life
Pressurizer Spray	1,500	108	509	66%	Fatigue-sensitive transient (see Note 1).
Loss of Offsite Power (Loss of RCS Flow)	40	0	1	98%	Not a fatigue-sensitive transient, but included in Unit 2 Technical Specifications. Assume 1 cycle occurs in 60-year life
Loss of Load	40	1	3	91%	Not a fatigue-sensitive transient, but included in Unit 2 Technical Specifications.

Note: 1. Projection is based on recent cyclic trends versus linear projection.

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."