NUREG-1779

Safety Evaluation Report
Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2

Docket Nos. 50-335 and 50-389

Florida Power & Light Company

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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Office of Nuclear Reactor Regulation
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ABSTRACT

This document is a safety evaluation report (SER) regarding the application to renew the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2, which the Florida Power and Light Company filed by letter dated November 29, 2001, and the U.S. Nuclear Regulatory Commission (NRC) received on November 30, 2001. The NRC Office of Nuclear Reactor Regulation has reviewed the license renewal application for compliance with the requirements of Title 10 of the *Code of Federal Regulations*, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

In its submittal of November 29, 2001, the Florida Power and Light Company requested renewal of the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2 (License Numbers DPR-67 and NFP-16, respectively), which were issued under Section 104b of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current license expiration dates of March 1, 2016, and April 6, 2023, respectively. Units 1 and 2 of the St. Lucie Nuclear Plant are located on Hutchinson Island in St. Lucie County, Florida. Each unit consists of a Combustion Engineering pressurized-water reactor nuclear steam supply system designed to produce a core thermal power output of 2,700 megawatts or approximately 890 megawatts electric.

The NRC license renewal project manager for St. Lucie Nuclear Plant, Units 1 and 2, is Noel Dudley. Mr. Dudley may be contacted by calling 301-415-1154 or by writing to the License Renewal and Environmental Impacts Program, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

Since its issuance, the SER has been revised to include Section 5, "Review by Advisory Committee on Reactor Safeguards." The revisions are identified by status bars in the left margins.

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ABBREVIATIONS

ac	alternating current
ACI	American Concrete Institute
AMP	aging management program
AMR	aging management review
ANS	
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AWWA	American Water Works Association
B&W	Babcock and Wilcox Co.
BL	bulletin
CASS	cast austenitic stainless steel
CEA	control element assembly
CCW	closed-cycle cooling water
CE	Combustion Engineering
CEOG	Combustion Engineering Owners Group
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CIS	containment isolation signal
CLB	current licensing basis
CMAA	Crane Manufacturers Association of American
CRDM	control rod drive mechanism
CRVS	control room ventilation system
CSB	core support barrel
CST	condensate storage tank
CUF	cumulative usage factor
C_vUSE	Charpy V-notch upper-shelf energy
CVCS	chemical and volume control system
CWST	city water storage tank
DBA	design-basis accident
DBD	design-basis document
DBE	design-basis events
dc	direct current
DG	diesel generator
DOE	Department of Energy
DOST	diesel fuel oil storage tank
DW	demineralized makeup water
ECCS	emergency core cooling system
EDG	emergency diesel generator

EFPY	effective full-power year
EOL	end of life
EPRI	electric power research institute
EQ	environmental qualification
ESF	engineered safety features
FAC	flow-accelerated corrosion
FHA	fuel-handling accident
FMP	fatigue monitoring program
FP	fire protection
FPL	Florida Power & Light Co.
FSAR	final safety analysis report
ft-lb	foot pound
GALL	generic aging lessons learned
GDC	general design criterion
GEIS	generic environmental impact statement
GL	generic letter
gpm	gallons per minute
GSI	generic safety issue
HEPA	high-efficiency particulate air
HMWPE	high molecular weight polyethylene
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and controls
IASCC	irradiation-assisted stress-corrosion cracking
ICW	Intake cooling water
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IPE	integrated plant examination
IPEEE	integrated plant examination of external events
IR	insulation resistence
ISA	Instrument Society of America
ISG	interim staff guidance
ISI	inservice inspection
J	joule
kPa	kilo pascal
ksi	kilograms per square inch

kV	kilovolts
kW	kilowatts
LBB	leak-before-break
LER	licensee event report
L/S	liters per second
LOCA	loss-of-coolant accident
LPSI	low-pressure safety injection
LRA	license renewal application
MBGS	miscellaneous bulk gas supply
MCIC	Metals and Ceramics Information Center
MCRE	main control room environment
Mev	million electron volts
MIC	micro biologically influenced corrosion
MNSA	mechanical nozzle seal assembly
MRP	material reliability project
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NELI	Nuclear Energy Insurance Limited
NEMA	National Electrical Manufactures
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NESC	National Electrical Association Safety Code
NRC	Nuclear Regulatory Commission, U.S.
NSSS	nuclear stem supply system
NUMARC	Nuclear Management and Resources Council
NUREG	NRC technical report designation
n/cm^2	neutron per square centimeter
OSHA	Occupational Safety and Health Administration
P&ID	piping and instrumentation drawing
PM	preventive maintenance
PORV	power-operated relief valve
ppb	parts per billion
ppm	Parts per Million
psi	pounds per square inch
PT	potential transformer
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
P-T	Pressure-Temperature
QA	quality assurance
RAI	request for additional information

RAB	reactor auxiliary building
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RI-ISI	risk-informed inservice inspection
RPV	reactor pressure vessel
RSG	replacement steam generator
RTD	resistance temperature detector
RT_{NDT}	reference temperature nil ductility temperature
RT_{PTS}	reference temperature pressurized thermal shock
RV	reactor vessel
RVH	reactor vessel head
RVI	reactor vessel internals
RWT	refueling water tank
SBO	station blackout
SBVS	shield building ventilation system
SC	structures and components
SCC	stress corrosion cracking
SE	safety evaluation
SEI/ASCE	Structural Engineering Institute/American Society of Civil Engineers
SER	safety evaluation report
SFP	spent fuel pool
SFPC	spent fuel pool cooling
SG	Steam Generator
SIAS	safety injection actuation signal
SOER	significant operating experience report
SPCS	steam and power conversion systems
SRP	standard review plan
SRP-LR	standard review plan license renewal
SSA	safe shutdown analyses
SSC	structure, system, and component
TGSCC	transgranular stress-corrosion cracking
TLAA	time-limited aging analysis
TS	technical specification
TSP	trisodium phosphate dodecahydrate
UFSAR	updated final safety analysis report
UHS	ultimate heat sink
USAS	United States of America Standards
USE	upper-shelf energy
UT	ultrasonic testing
VHP	vessel head penetration
XLPE	cross-linked polyethylene

1. INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) regarding the application to renew the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2, filed by Florida Power and Light Company (hereafter referred to as FPL or the applicant).

By letter dated November 29, 2001, FPL submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2, for an additional 20 years. The NRC received the application on November 30, 2001. The NRC staff reviewed the St. Lucie license renewal application (LRA) for compliance with the requirements of Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings. The NRC's license renewal project manager for St. Lucie Nuclear Plant, Units 1 and 2, is Noel Dudley. Mr. Dudley may be contacted by calling 301-415-1154, or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

In its application, FPL requested renewal of the operating licenses issued under Section 104(b) of the Atomic Energy Act of 1954, as amended, for St. Lucie Nuclear Plant, Units 1 and 2 (License Nos. DPR-67 and NPF-16, respectively), for a period of 20 years beyond the current license expiration dates of March 1, 2016, and April 6, 2023, respectively. Units 1 and 2 of St. Lucie Nuclear Plant are located on Hutchinson Island in St. Lucie County, Florida. Each unit consists of a Combustion Engineering pressurized-water reactor (PWR) nuclear steam supply system (NSSS) designed to produce a core thermal power output of 2,700 megawatts or approximately 890 megawatts electric. Details concerning the plant and the site are found in the updated final safety analysis report (UFSAR) for each unit.

The license renewal process proceeds along two tracks including a technical review of safety issues and an environmental review. The requirements for these two reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review is based on FPL's application for license renewal and on the applicant's answers to requests for additional information (RAIs) from the NRC staff. In meetings and docketed correspondence, FPL has also supplemented its answers to the RAIs. The public can review the license renewal application (LRA) and all pertinent information and material, including the UFSARs, at the NRC Public Document Room, 11555 Rockville Pike, Rockville, Maryland 20852-2738. In addition, the LRA for the St. Lucie Nuclear Plant, Units 1 and 2, and significant information and material related to the license renewal review are available on the NRC's Web site at www.nrc.gov.

This SER summarizes the findings of the staff's safety review of the LRA for the St. Lucie Nuclear Plant, Units 1 and 2, and describes the technical details considered in evaluating the safety aspects of its proposed operation for an additional 20 years beyond the terms of the current operating licenses. The staff reviewed the LRA in accordance with NRC regulations and the guidance presented in the NRC's NUREG-1800, "Standard Review Plan [SRP] for the Review of License Renewal Applications for Nuclear Power Plants," dated July 2001.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, licenses for commercial power reactors to operate are issued for 40 years. These licenses can be renewed for up to an additional 20 years. The original 40-year license term was selected on the basis of economic and antitrust considerations, not by technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC anticipated interest in license renewal and held a workshop on nuclear power plant aging. The results of the workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. On the basis of the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not involve technical issues that would preclude extending the life of nuclear power plants.

In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to life extension for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54. The NRC participated in an industry-sponsored demonstration program to apply the rule to pilot plants and to develop experience to establish implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly for the implementation of the maintenance rule, which also manages plant aging phenomena.

As a result, in 1995, the NRC amended the license renewal rule. The amended 10 CFR Part 54 established a regulatory process that was expected to be simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was clarified to focus on managing the adverse effects of aging, rather than identifying all aging mechanisms. The rule changes were intended to ensure that important structures, systems, and components (SSCs) will continue to perform their intended function during the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components.

In parallel with these efforts, the NRC pursued a separate rulemaking effort to amend 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal and fulfill, in part, the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Reviews

License renewal requirements for power reactors are based on two key principles.

(1) The regulatory process is adequate to ensure that the licensing bases of currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain SSCs during

the period of extended operation, and possibly a few other issues related to safety only during the period of extended operation.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner, and to the same extent, as during the original licensing term.

In implementing these two principles, the rule in 10 CFR 54.4 defines the scope of license renewal, including those plant SSCs (1) that are safety related, (2) whose failure could affect safety-related functions, and (3) that are relied on to demonstrate compliance with the Commission's regulations for fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), the applicant must review all SSCs that are within the scope of the rule to identify structures and components (SCs) that are subject to an aging management review (AMR). SCs that are subject to an AMR are those that perform an intended function without moving parts, or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period. As required by 10 CFR 54.21(a), the applicant must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of the SCs that are within the scope of license renewal will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation.

Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may occur for active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance indicators, and maintenance. The surveillance and maintenance programs and activities for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required to continue throughout the period of extended operation.

Pursuant to 10 CFR 54.21(b), each applicant is required to submit each year following the LRA, and at least 3 months before the scheduled completion of the NRC's review of the application, an amendment to the LRA that identifies any changes to the CLB for its facilities that materially affect the contents of the LRA, including the Final Safety Analysis Report (FSAR) supplements.

Another requirement for license renewal is the identification and updating of time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the initial operating term of the plant, and these assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or must be projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs will be adequately managed for the period of extended operation. Pursuant to 10 CFR 54.21(c)(2), each application must provide a list of exemptions granted pursuant to 10 CFR 50.12, which are, in effect, based on the TLAAs as defined in 10 CFR 54.3. Pursuant to CFR 54.21(c)(2), each application must also provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

Pursuant to 10 CFR 54.21(d), each application is required to include a supplement to the FSAR. This supplement must contain a summary description of the programs and activities for managing the effects of aging.

In July 2001, the NRC issued Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," and published NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." These documents describe methods acceptable to the NRC staff for implementing the license renewal rule, as well as techniques used by the NRC staff in evaluating applications for license renewals. The draft versions of these documents were issued for public comment on August 31, 2000 (65 FR 53047). The staff assessment of public comments was issued as NUREG-1739, "Analysis of Public Comments on the Improved License Renewal Guidance Documents." The regulatory guide endorsed an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54, The License Renewal Rule, Revision 3, issued in March 2001. The staff used the regulatory guide, along with the SRP, to review this application and to assess topical reports involved in license renewal as submitted by industry groups.

1.2.2 Environmental Reviews

In December 1996, the staff revised the environmental protection regulations in 10 CFR Part 51 to facilitate environmental reviews for license renewal. The staff prepared a "Generic Environmental Impact Statement [GEIS] for License Renewal of Nuclear Plants," NUREG-1437, Revision 1, in which it examined the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B.

Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. Analyses of the environmental impacts of renewing the license that must be evaluated on a plant-specific basis are identified as Category 2 issues in 10 CFR Part 51, Subpart A, Appendix B. Such analyses must be included in an environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the NRC performed a plant-specific review of the environmental impacts of license renewal, including whether there is new and significant information not considered in the GEIS for St. Lucie, Units 1 and 2. A public meeting was held on April 3, 2002, near St. Lucie, Units 1 and 2, as part of the NRC's scoping process to identify environmental issues specific to the plant. The results of the environmental review process and a preliminary recommendation on the license renewal action were documented in NRC's draft plant-specific Supplement 11 to the GEIS, issued in October 2002.

On December 3, 2002, during the 75-day comment period for the draft plant-specific supplement to the GEIS, another public meeting was held near the site. At this meeting, the staff described the environmental review process and answered questions from members of the public to assist them in formulating any comments they might have regarding the review.

Supplement 11 presents the NRC's environmental analysis associated with renewal of the St. Lucie Units 1 and 2 operating licenses for an additional 20 years. The analysis considers and weighs the environmental effects and alternatives available for avoiding adverse environmental effects.

On the basis of (1) the analysis and findings in the "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," (NUREG-1437), (2) the environmental report submitted by the applicant, (3) consultation with other Federal, State, and local agencies, (4) its own independent review, and (5) its consideration of public comments received during the scoping period, the staff recommended in Supplement 11 to NUREG-1437 that the Commission should determine whether the adverse environmental impacts are not so great that preserving the option of license renewal for energy planning would be unreasonable.

1.3 Summary of the Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the St. Lucie Nuclear Plant, Units 1 and 2, LRA in accordance with Commission guidance and the requirements of 10 CFR 54.4, 54.19, 54.21, 54.22, 54.23, and 54.25. The standards for renewing a license are contained in 10 CFR 54.29.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. FPL submitted this general information in an enclosure to its November 29, 2001, letter regarding the application for renewed operating licenses for St. Lucie Nuclear Plant, Units 1 and 2. The staff reviewed that enclosure and found that the applicant submitted the information required by 10 CFR 54.19(a).

In 10 CFR 54.19(b), the Commission requires that LRA include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The applicant stated the following in its renewal application regarding this issue:

> The current indemnity agreement for St. Lucie Units 1 and 2 states, in Article VII, that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as revised by Amendment No. 10, lists four license numbers. Should the license numbers be changed upon issuance of the renewed licenses, FPL requests that the conforming changes be made to Item 3 of the Attachment, and to any other sections of the indemnity agreement as appropriate.

The staff will use the original license number for the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility must contain (a) an IPA, (b) CLB changes during the NRC review of the application, (c) an evaluation of TLAAs, and (d) an FSAR supplement. On November 29, 2001, the applicant submitted the information required by 10 CFR 54.21(a), (c), and (d) in the enclosure of its LRA. This enclosure is entitled "Application for Renewed Operating Licenses, St. Lucie Units 1 and 2." By letter dated March 27, 2003, the applicant stated that it had reviewed facility changes since the submittal of the St. Lucie LRA and that none of the CLB changes materially affected the contents of the LRA. This submittal satisfies the requirement of 10 CFR 54.21(b).

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. The applicant did not request any changes to the plant technical specifications in its LRA.

The staff evaluated the technical information required by 10 CFR 54.21 and 54.22 in accordance with the NRC's regulations and the guidance provided in the initial draft standard review plan (SRP). The staff's evaluation of this information is documented in Chapters 2, 3, and 4 of this SER.

The staff's evaluation of the environmental information required by 10 CFR 54.23 is documented in the plant-specific supplement to the GEIS (NUREG-1437, Supplement 5), that states the considerations related to renewing the licenses for St. Lucie Units 1 and 2.

1.4 Differences in the Designs of St. Lucie Units 1 and 2

St. Lucie Unit 1 was licensed approximately 7 years before St. Lucie Unit 2. During these 7 years, significant industry events occurred including the Three Mile Island Unit 2 event and the Browns Ferry fire event. The lessons learned from these events and other activities resulted in differences between St. Lucie Units 1 and 2. Even though the units are of the same design and the systems fulfill the same functional design requirements, some of the component design features are different.

For design-basis accidents (DBA), the Unit 1 spent fuel pool (SFP) is designed to remove decay heat by means of SFP boiling. The associated Unit 1 SFP makeup systems are comprised of seismically qualified piping from the discharge headers of the two intake cooling water system loops. Other non-safety-related makeup systems are available for normal makeup to the pool. The Unit 2 spent fuel pool cooling system, which consists of two pumps and a redundant set of heat exchangers, is designed to remove decay heat from the spent fuel during DBA. The Unit 2 SFP makeup systems are similar to the Unit 1 makeup systems.

The Unit 1 fuel handling equipment is not within the scope of license renewal, since the results of the Unit 1 UFSAR analysis of a fuel handling accident indicated that offsite exposures would be less than those referenced in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), and 10 CFR 100.11. Because of the predicted radiological consequences of a fuel element drop accident, Unit 2 fuel handling equipment is within the scope of license renewal.

Unit 1 was designed to protect against single missiles. To meet this design requirement, the licensee provided for redundancy and separation of SCs or provided missile barriers around safety-related components. Unit 2 was designed to protect against multiple missiles, including vertical missiles. To meet this design requirement, the licensee enclosed the Unit 2 component cooling water area, condensate storage tank, and emergency diesel generator fuel oil storage tanks in buildings. These buildings and the Unit 1 missile barriers are within the scope of license renewal.

The Unit 1 turbine building is within the scope of license renewal since it contains two safety-related motor-operated valves and their associated power cables. The Unit 2 turbine building contains no safety-related equipment; however, the building is within the scope of license renewal because of installed non-safety-related equipment related to regulatory events.

The Unit 1 and 2 condensate storage tanks are within the scope of license renewal because they are safety-related components. The Unit 1 condensate storage tank is in an outdoor environment and is protected by a missile shield comprised of a concrete wall around the tank. The Unit 2 condensate storage tank is in an indoor - not-air-conditioned environment. The condensate storage tank cross-connect piping for Unit 1 is within scope of license renewal because it is a non-safety-related component whose failure could prevent satisfactory accomplishment of safety-related functions. The cross-connect piping allows operators to line up the Unit 1 auxiliary Feedwater system to take a suction from the Unit 2 condensate storage tank.

The Unit 1 demineralized water system piping in the diesel generator building was not designed as seismic Category 1. However, the piping is within the scope of license renewal because postulated failure of the piping could prevent satisfactory accomplishment of safety-related functions. The Unit 2 demineralized water system piping in the diesel generator building was designed as seismic Category 1 and is within the scope of license renewal.

The fire protection system is common to both Units 1 and 2 and is within the scope of license renewal. The system consists of two fire pumps powered from the Unit 1 electrical system. The Haloed suppression system for the cable spreading room is unique to Unit 1. The use of primary water for the hose station water supply in the containment is unique to Unit 2.

For station blackout considerations, Unit 1 credits the Unit 2 emergency diesel generators as the alternative alternating current (AC) sources. Unit 2 is a 4-hour direct current (DC) coping plant. For Unit 1, instrument air is required to operate valves used to remove decay heat during an SBO. Therefore, the instrument air system and a portion of the turbine cooling water system are within the scope of license renewal. For Unit 2, the similar decay heat removal valves are operated by DC power and, therefore, the Unit 2 instrument air system is not within the scope of license renewal.

The Unit 1 refueling water tank is aluminum and has experienced aging degradation. The applicant identified three different programs for managing the aging effects. The Unit 2 refueling water tank is stainless steel, and the applicant identified a single program for managing the aging effects. The Unit 1 spent fuel racks contain Boraflex inserts. The applicant identified a program for managing the aging of these inserts. The Unit 2 fuel racks do not contain Boraflex inserts and, therefore, the applicant did not identify any aging management programs for Unit 2.

Significant maintenance activities are listed below.

- The licensee replaced the Unit 1 steam generators in 1997.
- The licensee removed the thermal shield and repaired damage to the Unit 1 core support barrel in 1983.

1.5 Interim Staff Guidance

The interim staff guidance (ISG) process provides review and control of new staff positions related to license renewal. These new staff positions are not regulations but provide an approach acceptable to the staff for meeting regulatory requirements. The applicant does not have to follow the interim staff guidance but does have to demonstrate that its alternative method complies with the regulations. The following sections identify where the staff reviewed the applicant's response to the specific interim staff guidance.

1.5.1 Station Blackout Scoping

The staff's review of the applicant's scoping and screening methodology for systems required in response to the station blackout rule 10 CFR 50.63 is contained in Section 2.1.3.1 of this SER. The staff's scoping and screening findings associated with station blackout are contained in Section 2.3.5 of this SER. The staff's review of the applicant's AMR of the structures and components added to the scope of license renewal is contained in Section 3.6.4 of this SER.

1.5.2 Concrete Aging Management Program

The staff's review of the applicant's addition of several concrete components to the systems and structures monitoring program is contained in Section 3.0.5.10 of this SER.

1.5.3 Identification and Treatment of Electrical Fuses

The staff's review of the applicant's addition of fuse holders to the scope of license renewal is contained in Section 3.6.2.1 of this SER.

1.5.4 Identification and Treatment of Housing for Active Components

The staff's review of the applicant's addition of housings for active components to the scope of license renewal is contained in Sections 2.3.2.1, 2.3.3.14, and 2.3.3.15 of this SER. The staff's review of the applicant's AMR of these added components is contained in Section 3.3.17.7 of this SER.

1.5.5 Scoping Criteria 54.4(a)(2)

The staff's review of the applicant's scoping and screening methodology for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of safety-related functions is contained in Section 2.1.3.1 of this SER. The review included seismic II over I considerations. The staff's review of the applicant's scoping and screening findings associated with the application of a spaces approach is contained in Section 2.3.5 of this SER. The staff's review of the applicant's aging management review of the auxiliary systems added to the scope of license renewal is contained in Section 3.3.17.7 of this SER.

1.6 Summary of Open and Confirmatory Items

As a result of its review, the staff issued an SER with open items on February 7, 2003, which documented 11 open items and 8 confirmatory items. The staff characterized an issue as an open item if the applicant had not presented a sufficient basis for resolution, or if the findings of an NRC inspection had not been documented prior to the issuance of the SER with open items. The staff characterized an issue as a confirmatory item if the staff and applicant had agreed to a resolution but the applicant had not submitted the agreed upon information.

1.6.1 Open Items

Open Item 3.0.2.2-1: The staff conducted an onsite aging management program (AMP) inspection, which included verification of the applicant's claim that some aging management programs are consistent with the GALL Report. The inspection also verified information concerning the scoping and screening results. The inspection was completed on January 31, 2003, and a report documenting the inspection findings was not available at the time the SER with open items was issued.

The staff issued Inspection Report 50-335/2003-3 and 50-389/2003-03 on March 7, 2003. The inspection findings confirmed the claim that specified AMPs, were consistent with GALL Report AMPs, and the inspection findings concerning scoping and screening results supported the conclusions in this SER. The staff considers Open Item 3.0.2.2-1 closed.

Open Item 3.0.5.7-1: This item concerns the detection of wall thinning of FP piping due to internal corrosion. The applicant stated that the internal loss of material can be detected by changes in flow or pressure, by leakage, or by evidence of excessive corrosion products during flushing of the system. The applicant also stated that St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable. *In the SER with Open Items issued on February 7, 2003, the staff stated that In* accordance with ISG-4, "Aging Management of Fire Protection Systems for License Renewal," the applicant should perform a baseline pipe wall thickness evaluation of the FP piping using a nonintrusive means, such as a volumetric inspection, before the current license term expires. Alternatively, the applicant should provide assurance that adequate wall thickness evaluations on representative piping exist such that a baseline wall thickness evaluation is not necessary.

In its supplemental response dated March 28, 2003, the applicant explained that it had performed volumetric inspections of 4 and 6 inch piping in stagnant portions of the fire protection system. In addition, the applicant performed a corrosion rate analysis, using the results of the volumetric inspections and the nominal wall thickness of the new pipe, and concluded that the pipe wall thickness at the end of the extended period of operation would be greater than the wall thickness required by the ANSI B3.1 code. On the basis of the results of the volumetric inspection and the analysis, the staff concludes that the applicant has adequately addressed the internal corrosion of stagnant portions of the fire protection system piping. The staff considers Open Item 3.0.5.7-1 closed.

Open Item 3.0.5.10-1: Several components in the intake cooling water system credit the Systems and Structures Monitoring Program for managing loss of material in the raw water environment. In RAI B.2.10-2, the staff asked the applicant to justify the adequacy of this program for managing the aging effects on specific components in the intake cooling water system. The staff finds the applicant's response does not adequately address the aging management of the small valves, piping/tubing/fittings, thermowells, and orifices. The applicant, in a letter dated November 27, 2002, provided additional information concerning the materials, operating history, and repair history of the small valves, piping/tubing/fittings, *thermowells, and orifices in the intake cooling water system.* However, the applicant also relies on leakage detection for aging management of some components. It is the staff's position that leakage detection does not provide adequate aging management because leakage frequently indicates a loss of component intended function. The staff created Open Item 3.0.5.10-1 to address the use of leakage detection.

In its supplemental response dated March 28, 2003, the applicant stated that intake cooling water system operating experience has demonstrated that leakage has resulted from small corrosion cells where localized failures of the coatings occur. The applicant explained that a small amount of leakage will not impact the system function. In addition, operating experience has demonstrated that the structural integrity of the system has been maintained and corrective actions have led to replacement of approximately 75 percent of the small bore piping with corrosion-resistant materials.

For the intake cooling water (ICW) system, operating experience has demonstrated that the leakage results from small corrosion cells where localized failures of the coatings occur. The small amount of leakage will not impact the system function, the operating experience has demonstrated that the structural integrity of the system is maintained, and corrective actions have led to replacement of approximately 75 percent of the small bore piping with corrosion-resistant materials. For the chemical and volume control system, the applicant has removed the source of the aggressive environment, performed inspections, and replaced piping as necessary. Operating experience has indicated only two instances (one on each unit) of minor leakage. The staff concludes that the Systems and Structures Monitoring Program is adequate to detect aging in the intake cooling water and chemical and volume control systems. The staff considers Open Item 3.0.5.10-1 closed.

Open Item 3.1.0.1-1: A commitment is requested to implement any recommended inspection methods, inspection frequencies, and acceptance criteria that result from industry initiatives by the Combustion Engineering Owner's Group (CEOG), the NEI, or the Electric Power Research Institute (EPRI) Materials Reliability Project Integrated Task Group concerning Inconel materials. The staff also requested a commitment to implement any further requirements that may result from the staff's resolution of the issue of primary water stress-corrosion cracking (PWSCC) in nickel-based alloy components, including those that may result from the staff's resolution of the industry's responses to NRC Bulletin 2002-02 and/or resolution of the V.C. Summer issue.

In its reply to Open Item 3.1.0.1-1, the applicant agreed to implement commitments made in response to any future NRC communications associated with primary water stress corrosion cracking in nickel-based alloy components. The applicant also stated that evaluation of the work performed by the EPRI Material Reliability Program and NEI for inclusion in its Alloy 600 Inspection Program is an integral part of the program. On February 11, 2003, the staff issued generic NRC Order EA-03-009. The Order contains augmented volumetric, surface, and bare surface visual inspection requirements for the reactor vessel head and associated penetration nozzles. The requirements in the Order augment any prior inspection programs that the applicant committed to in response to NRC Bulletin 2002-02. The staff concludes that the applicant's response to the Order and implementation of the commitments made in response to Open Item 3.1.0.1-1 will ensure the structural integrity of the reactor vessel heads and other nickel-based alloys in the primary coolant system during the period of extended operation. The staff considers Open Item 3.1.0.1-1 to be resolved.

Open Item 3.1.0.1-2: In its response to RAI 3.2.1-1, the applicant states that the A600IP includes commitments made in the applicant's responses to NRC Bulletin 2002-01 (FPL letters

L-2002-061 and L-002-116 dated April 2, 2002, and June 27, 2002, respectively) and NRC Bulletin 2002-02 (FPL letter L-2002-185 dated September 11, 2002). The responses to these bulletins are specific to degradation that may occur in the St. Lucie reactor vessel heads (RVHs) and associated penetration nozzles and attachment welds. The responses to these bulletins do not address degradation that may occur in nickel-based alloy components of other Class 1 reactor coolant system (RCS) subsystems such as those in the pressurizers, steam generators, hot legs, and reactor vessel internals. The applicant should clarify the inspection programs for the remaining Class 1 nickel-based alloy base metal and weld components, other than RVH penetration nozzles and their attachment welds.

In its supplemental response dated March 28, 2003, the applicant clarified that the A600IP applies to the other nickel-based alloy components in the reactor coolant system including reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, RCS piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings, and RCS dissimilar metal welds. The applicant clarified that the A600IP for the other nickel-based alloy components is performed in conjunction with visual and other examinations that follow the American Society of Mechanical Engineers (ASME) Section XI, IWB, IWC, and IWD, Inservice Inspection Program and the Boric Acid Wastage Surveillance Program. The staff concludes that the applicant's response to Open Item 3.1.0.1-2 is acceptable since the Alloy 600 Inspection Program will be periodically revised and is applicable to the nickel-based alloy components in the RCS. The staff considers Open Item 3.1.0.1-2 closed.

Open Item 3.1.0.3-1: If the risk-informed methodologies for the Small Bore Class 1 Piping Inspection AMP are part of a risk-informed inservice inspection (RI-ISI) program that is required to be approved under the provisions of 10 CFR 50.55a(a)(3), the potential exists for methodologies to "screen out" the volumetric examinations of the small bore piping based on risk information and therefore eliminate the volumetric examinations proposed for the small bore Class 1 piping components. In Section 18.1.5 of Appendix A1 for St. Lucie 1 and Section 18.1.14 of Appendix A2 of the LRA, the applicant commits to submitting the inspection plan for Class 1 small-bore piping prior to the end of the initial licensing periods for the units. When this inspection plan is submitted to the staff, the staff requests that the applicant confirm that the risk-informed methodologies for the small bore Class 1 piping inspection will be used only to establish the minimum number and locations of the small bore Class 1 piping full-penetration butt welds to be volumetrically examined and will not be used as a basis to eliminate the volumetric examinations for the welds.

The staff also asks that applicant describe the risk-informed methodology in the inspection plan and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The applicant should also confirm that the inspection plan for the small bore piping will include this information when submitted to the staff as part of the FSAR supplements summary descriptions for the small bore Class 1 piping inspection AMP.

In its supplemental response dated March 28, 2003, the applicant stated that the small bore inspection plan will confirm that the risk-informed methodologies for the small bore Class 1 piping inspection will be used only to establish the minimum number and locations of the small bore piping welds to be examined. The applicant also stated that the methodology will not be used as a basis to eliminate the volumetric examination of the welds. The applicant explained that the inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The staff concludes that the applicant's response is acceptable. The staff considers Open Item 3.1.0.3-1 closed.

Open Item 3.1.0.5-1: The applicant described the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. In accordance with American Society for Testing and Materials (ASTM) E185, for current 40-year practice, it is recommended that the last capsule to be removed should receive the same or higher fluence than the peak end of life (EOL) fluence. Therefore, the applicant should provide updated capsule removal schedules that reflect a capsule to be withdrawn with a predicted fluence equal to or greater than the peak EOL fluence for the extended period of operation for St. Lucie Units 1 and 2.

In its supplemental response dated March 28, 2003, the applicant indicated that the predicted 60-year EOL peak fluence for Unit 1 is 4.24 X 10^{19} n/cm^2, based on 52 effective full-power years (EFPYs) of operation, and the predicted 60-year EOL peak fluence for Unit 2 is 4.56 X 10^{19} n/cm^2, based on 55 EFPYs of operation. As indicated in the applicant's LRA reactor pressure vessel surveillance capsule withdrawal schedules, the final surveillance capsule for Unit 1 is to be withdrawn at a fluence of 4.4 X 10^{19} n/cm^2, and the final Unit 2 capsule is to be withdrawn at a fluence of 4.56 X 10^{19} n/cm^2. Based on these values, the staff verified that the last capsules to be withdrawn from Units 1 and 2 would satisfy the recommendation of the latest endorsed edition of ASTM E185. The staff considers Open Item 3.1.0.5-1 closed.

Open Item 3.1.1.2-1: The applicant has not identified in Table 3.1-1 and Section 3.1.1.2 of the LRA that loss of mechanical closure integrity is an applicable effect for the stainless steel or carbon steel non-Class 1 bolting materials as a result of stress relaxation. The applicant should provide the basis for not considering stress relaxation to be an applicable aging effect mechanism for the stainless steel and carbon steel non-Class 1 bolting materials. If loss of mechanical closure integrity due to stress relaxation is considered to be an applicable effect for the stainless steel and carbon steel non-Class 1 bolting materials, the applicant should provide revised AMRs for these bolting materials to reflect that loss of mechanical closure integrity is an applicable effect for these bolting materials and propose an applicable inspection-based AMP to manage loosening of the bolts during the extended periods of operation.

In its supplemental response dated March 28, 2003, the applicant clarified that the threshold for stress relaxation of bolted connections is 700 °F or higher for non-Class 1 bolted connections. The applicant stated the operating temperature for the RCS is well below this threshold. The staff concludes that the applicant's response provides an acceptable basis for omitting stress relaxation as an applicable aging effect mechanism for the non-Class 1 RCS bolting because the bolts will not be exposed to temperatures in excess of the threshold for stress relaxation in the bolting materials. The staff considers Open Item 3.1.1.2-1 closed.

Open Item 3.1.2.2-1: The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 materials and are welded to the low-alloy steel pressurizer surge and spray nozzles using Alloy 182/82 weld metals. Industry experience has demonstrated that these weld materials are susceptible to PWSCC. In its AMR provided October 3, 2002, the applicant concluded that there are no applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves because the applied loads on the thermal sleeves are low. The attachment welds for the pressurizer surge and spray nozzle thermal sleeves may contain high residual stresses that result from solidification of the weld metal from the molten state. Therefore, the staff concludes that the attachment weld for the pressurizer surge and spray nozzle thermal sleeves may be susceptible to cracking as a result of PWSCC, and that the applicant's supplemental AMR for the pressurizer thermal sleeves needs to be revised to include cracking as an applicable effect for the components.

By letter dated June 24, 2003, the applicant submitted additional information in order to support its basis that circumferential cracking of a thermal sleeve is not an aging effect requiring aging management. The applicant's supplemental RAI response provides an acceptable basis for concluding that any postulated cracking of a pressurizer surge or spray nozzle thermal sleeve is likely to be oriented in the axial orientation because the circumferential stresses, which could potentially lead to the initiation of an axially oriented crack, are limiting relative to any axially oriented stresses that could potentially lead to the initiation of an circumferentially oriented crack. The applicant's information also provides an acceptable technical basis for concluding, that while circumferential cracking is not likely, complete cracking of a thermal sleeve would not result in the generation of a loose part internal to the St. Lucie pressurizer shells. Based on this assessment and the leakage-thermal fatigue analysis, the staff concurs that neither axial cracking nor circumferential cracking requires aging management for pressurizer surge and spray nozzle thermal sleeves. The staff considers Open Item 3.1.2.2-1 closed.

Open Item 3.6.2.1-1: Operating experience, as discussed in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connections surfaces can result in fuse holder failure. On this basis, fuse holders, including both the insulation material and the metallic clamps, are subject to both an AMR and AMP for license renewal. Typical plant effects observed from fuse holder failure due to aging have resulted in challenges to safety systems, cable insulation failure due to over-temperature, failure of the containment spray pump to start, a reactor trip, etc. Therefore, managing age-related failure of fuse holders would have a positive effect on the safety performance of a plant. Information Notices 91-78, 87-42, and 86-87 are examples that underscore the safety significance of fuse holder and the potential problems that can arise from age-related fuse holder failure.

Open Item 3.6.2.1-1 was related to the aging effects identified in ISG-5 on the identification and treatment of electrical fuse holders for license renewal. The fuse holders include both the insulation material and metallic clamps. The EQ cables and connections AMP will manage the aging of insulation material but not the metallic portions. In the ISG, the staff indicates that the AMR for fuse holders (metallic clamps) needs to include the following stressors if applicable—fatigue, mechanical stress, vibration, chemical contamination, and corrosion. Where environments or operating conditions preclude such aging effects (e.g., fuse holders not subject to vibration from rotating machinery), they need not be addressed by the AMP.

The applicant states that the only fuse holders that were not part of large, active assembly are those installed to provide double isolation for non safety-related loads powered from safety-related power supplies. The applicant addressed each aging effect identified in the ISG and provided technical justification of why an AMP for the metallic portions of these fuse holders is not required. The staff agreed with the applicant's determination that the environments and/or operating conditions of the fuse holders preclude the aging effects identified in ISG-5. The staff finds that an AMP for the metallic portions of fuse holders is not required. The applicant also reviewed IN 86-87, 87-42, and 91-78 to see if the aging effects identified in the INs were applicable to the fuse holders at St. Lucie. The applicant concluded, and the staff concurred, that the above INs are not applicable to the fuse holders at St. Lucie because of differences in usage, design, and construction. The staff, therefore, found the applicant's response to the open item acceptable. The staff considers Open Item 3.6.2.1-1 closed.

Open Item 4.6.4-1: The staff is in the process of reviewing Topical Report WCAP-15973-P; Class 2 Proprietary Calculation CN-CI-02-60,and the applicant's January 8, 2003, relief request for the St. Lucie half- nozzle designs. These documents represent the most up-to-date current licensing basis (CLB) for the TLAA on the St. Lucie Alloy 600 half-nozzle repairs. The acceptability of TLAA 4.6.4 is pending acceptable approval of these documents. The FSAR supplement summary descriptions for TLAA 4.6.4, "Alloy 600 Instrument Nozzle Repairs," as given in Sections 18.3.8 of LRA Appendix A1 and 18.3.7 of LRA Appendix A2, do not currently reflect that these documents are part of the CLB for the TLAA on the Alloy 600 instrument nozzle repairs. To ensure that the FSAR supplement summary descriptions for this TLAA are up to date, the applicant should supplement the FSAR supplement summary descriptions, as given in Section 18.3.8 of Appendix A1 and Section 18.3.7 of Appendix A2 to the LRA, to include a reference to Topical Report WCAP-15973-P; Class 2 Proprietary Calculation CN-CI-02-60; and the January 8, 2003, relief request for St. Lucie half-nozzle designs.

In a letter dated April 25, 2003 (FPL Letter L-2003-096), the applicant submitted a supplemental response to Open Item 4.6.4-1. In this response, the applicant confirmed that the fatigue crack growth assessment for the half-nozzle replacement designs is given in Class 2 Proprietary Calculation CN-CI-02-60. The applicant stated that an ASME Section XI relief request for the half-nozzle designs was submitted for NRC review and approval on January 8, 2003. This relief request is currently under review by the staff. In its response, the applicant committed the following:

> Implement all reasonable alternative inspection/evaluation methods that may be required by the NRC, as appropriate, as conditions for approval of the relief request. Subsequent to the disposition of the relief request and prior to the period of extended operation, the TLAAs for the St. Lucie Units 1 and 2 half-nozzle replacement designs will be dispositioned pursuant to 10 CFR 54.21(c)(1). These TLAAs shall address: 1) the potential growth of the original flaw due to thermal or mechanical cycling, and 2) the potential wastage of the ferritic material that is adjacent to the half-nozzle configuration and exposed to borated reactor coolant. If acceptability of the St. Lucie Units 1 and 2 half-nozzle designs cannot be demonstrated for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(i) or 54.21(c)(1)(ii), then these TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) which may include appropriate nozzle replacement to comply with ASME Section III and ASME Section XI replacement criteria.

The applicant's response to Open Item 4.6.4.1 incorporates a commitment that reflects the need to implement the TLAAs for the small-bore nozzle repairs that use the methods in the requested documents. This commitment is tracked as Item 21 of Table 1 to SER Appendix D (i.e., the commitment table for St. Lucie Unit 1) and Item 19 of Table 2 to SER Appendix D (i.e., the commitment table for St. Lucie Unit 2). Based on the applicant's commitment, the staff considers Open Item 4.6.4-1 closed.

1.6.2 Confirmatory Items

Confirmatory Item 2.3.3.7-1: In its initial response to RAI 2.3.3-4, regarding makeup water pathways, the applicant described the availability of makeup from the refueling water storage and primary water tanks, and stated that both UFSARs for Units 1 and 2 describe the intake cooling water source of makeup water as a seismic Category I backup supply of spent fuel pool makeup water. The applicant also noted that only salt water makeup from intake cooling water is credited in the safety analysis for makeup to the Units 1 and 2 spent fuel pools.

Although the UFSARs and previous staff evaluations for St. Lucie Units 1 and 2 include the fresh water sources as the preferred method to mitigate a loss of spent fuel pool coolant inventory, the staff previously concluded that the addition of salt water from the intake cooling water system can be aligned in sufficient time and provide adequate makeup capacity to assure an adequate coolant inventory is maintained in the spent fuel pool. Therefore, this makeup path alone is sufficient to satisfy the LR scoping criteria of 10 CFR 54.4 (a)(1). The freshwater makeup sources provide a redundant capability that is not required to be within the scope of LR in accordance with 10 CFR 54.4 (a)(2).

During a telephone call on February 3, 2003, the applicant agreed to resubmit its October 3, 2002, response to RAI 2.3.3-4. At the request of the staff, the applicant agreed to remove the paragraphs that contained the applicant's assessment of the plant design as referenced in the UFSARs and to state that the intake cooling water makeup to the spent fuel pool meets the scoping requirement of 10 CFR 54.4. This was Confirmatory Item 2.3.3.7-1.

By letter dated March 28, 2003, the applicant provided a supplemental response to RAI 2.3.3-4. This response describes the CLB with respect to spent fuel pool makeup capability based on the aforementioned licensing correspondence, dated June 7, 1974. As described above, this information provided an adequate basis to conclude that the screening criteria of 10 CFR 54.4(a)(1) are satisfied by the makeup lines from the intake cooling water system. The information requested by the staff to be removed was appropriately deleted. Therefore, the staff considers Confirmatory Item 2.3.3.7-1 closed.

Confirmatory Item 3.0.2.2-1: The applicant claims that several of its aging management programs are consistent with specific AMPs in the Generic Aging Lessons Learned Report. In Appendix B of the LRA, the applicant describes the AMPs that are consistent with the GALL Report and identifies the specific GALL Report AMPs. However, the information concerning the specific GALL Report AMPs is not included in the FSAR supplements in Appendix A of the LRA. The applicant agreed to include a reference to specific GALL Report AMPs in the FSAR supplements concerning the AMPs that are consistent with the GALL Report.

In it supplemental response dated March 28, 2003, the applicant provided revised sections for the Unit 1 and 2 FSAR supplements that identified the specific GALL Report AMPs associated with the AMPs that are consistent with the GALL Report. The staff verified that the appropriate GALL Report AMP was added to Sections 18.1.6, 18.2.2.1, 18.2.2.2, 18.2.2.3, 18.2.3, 18.2.4, 18.2.5, 18.2.6, 18.2.9 of Appendix A1 of the LRA and Sections 18.1.5, 18.2.2.1, 18.2.2.2, 18.2.2.3, 18.2.3, 18.2.4, 18.2.5, 18.2.8, 18.2.12 of Appendix A2 of the LRA. The staff considers Confirmatory Item 3.0.2.2-1 closed.

Confirmatory Item 3.0.5.1-1: Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 of the LRA provide descriptions of the Galvanic Corrosion Susceptibility Inspection Program. The program descriptions are consistent with the material contained in Section 3.1.2 of Appendix B of the LRA, with the exception of the areas of acceptance criteria and inspection technique. The applicant needs to revise the sections of the FSAR supplements to describe these two attributes consistent with the SER.

In its supplemental response dated March 28, 2003, the applicant provided revised Units 1 and 2 FSAR supplements that include descriptions of the acceptance criteria and inspection techniques contained in Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 of the LRA for the Galvanic Corrosion Susceptibility Inspection Program. The staff considers Confirmatory Item 3.0.5.1-1 closed.

Confirmatory Item 3.0.5.4-1: In Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 of the LRA, the applicant provides descriptions of the Boric Acid Wastage Surveillance Program. The staff reviewed these sections of the FSAR supplements to verify that the information was an adequate summary of the program activities required by 10 CFR 54.21(d). The staff determined that the applicant should revise these sections to include additional portions of the waste management system that are within the scope of license renewal.

In its supplemental response dated March 28, 2003, the applicant provided revised sections of the FSAR supplements that include additional portions of the waste management system. The staff considers Confirmatory Item 3.0.5.4-1 closed.

Confirmatory Item 3.1.0.1-1: Sections 18.2.1 of Appendices A1 and A2 of the LRA provide the applicant's FSAR supplements for Units 1 and 2 associated with the A600 Inspection Program. The program descriptions are consistent with the material contained in Section 3.2.1 of Appendix B to the LRA, with the possible exception of changes to the attributes of detection of aging effects, monitoring and trending, and acceptance criteria resulting from the applicant's responses to Open Items 3.1.0.1-1 and 3.1.0.1-2. The applicant needs to revise the FSAR supplements to describe these attributes consistently with its responses to Open Item 3.1.0.1-1 and 3.1.0.1-2.

In its supplemental response dated March 28, 2003, the applicant provided revised FSAR supplements that incorporate information associated with the applicant's responses to Open Items 3.1.0.1-1 and 3.1.0.1-2. The staff considers Confirmatory Item 3.1.0.1-1 closed.

Confirmatory Item 3.1.0.3-1: The applicant provides summary descriptions for the Small Bore Class 1 Piping Inspection AMP in Section 18.1.5 of LRA Appendix A1 for St. Lucie Unit 1 and Section 18.1.4 of LRA Appendix A2 for St. Lucie Unit 2. The applicant states that a volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. The applicant also states that this is a one-time inspection that will address Class 1 piping less than 4 inches in diameter. On the basis of the results of these inspections, the applicant will determine the need for additional inspections or programmatic corrective actions. The applicant states that it will provide the NRC with a report describing the inspection plan prior to its implementation and that the inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1. The contents of these sections are consistent with the description provided in Section 3.1.5 of Appendix B to the LRA and reflect the need for the applicant to submit the inspection plan and risk-informed methodology for the Small Bore Class 1 Piping Inspection to the staff for review and approval prior to implementation of the inspection.

The staff considers the risk-informed program for the small bore Class 1 piping to be an alternative to the ISI requirements of Section XI of the ASME Boiler and Pressure Vessel Code for ASME Code Class 1 components. The applicant is required to submit this program under the provisions of 10 CFR 50.55a(a)(3) for approval of alternatives to Section XI of the ASME

Boiler and Pressure Vessel Code. The staff informed the applicant that the FSAR supplements describing the Small Bore Class 1 Piping Inspection should be revised to include the information provided in response to Open Items 3.1.0.3-1 parts 1 and 2. This was Confirmatory Item 3.1.0.3-1.

In its supplementary response dated March 28, 2003, the applicant provided revised FSAR supplements that incorporated descriptions of the inspection plan and risk-informed methodology information requested by the staff in Open Item 3.1.0.3-1. The staff concludes that the applicant's response is acceptable. The staff considers Confirmatory Item 3.1.0.3-1 closed.

Confirmatory Item 3.6.2.1-1: The applicant committed to provide a description of the non-EQ cables and connections AMP to be added in the FSAR supplements in Appendix A of the LRA.

In its supplemental response dated March 28, 2003, the applicant provided new Section 18.1.7 for the Unit 1 FSAR supplement and new Section 18.1.6 for the Unit 2 FSAR supplement that describe the Containment Cable Inspection Program. The staff verified the contents of the sections and considers Confirmatory Item 3.6.2.1-1 closed.

Confirmatory Item 4.3.1-1: The applicant stated that the Inservice Inspection Program would be used to manage the aging of the pressurizer surge line during the period of extended operation. The applicant plans to use the results of the Inservice Inspection Program to develop an approach for addressing environmentally assisted fatigue of the surge line. If the applicant selects the approach of using an inspection program, the inspection details including scope, qualification, method, and frequency shall be provided to the NRC for review before the period of extended operation. The staff finds that the applicant's proposed options are acceptable to address environmentally assisted fatigue of the pressurizer surge lines during the period of extended operation in accordance with 10 CFR 54.21(c)(1). However, in accordance with 10 CFR 54.21(d), these options need to be included in the FSAR supplements.

In its supplemental response dated March 28, 2003, the applicant provided updated FSAR supplements for St. Lucie Units 1 and 2 that describe the applicant's proposed options for addressing environmentally assisted fatigue of the pressurizer surge lines during the period of extended operation. The staff considers Confirmatory Item 4.3.1-1 closed.

2. STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

This chapter documents the staff's review of the methodology used by the applicant to develop its integrated plant assessment (IPA) and the results of the IPA. The staff's review of the methodology is presented in Section 2.1 of this Safety evaluation report (SER). The staff's review of the IPE results is presented in Sections 2.2 through 2.5 of this SER.

By letter dated November 29, 2001, Florida Power and Light Company submitted its license renewal application (LRA) for St. Lucie Units 1 and 2. As an aid to the staff, the applicant provided license renewal boundary drawings that identified the functional boundaries for systems and components within the scope of license renewal. These boundary drawings are not part of the license renewal application.

The staff issued requests for additional information (RAIs) concerning the applicant's IPA methodology and results in letters dated July 1, 18, and 29, 2002. The applicant responded to these RAIs in letters dated September 26, October 3, November 27, and December 23, 2002.

The staff conducted a scoping and screening methodology audit at the St. Lucie Nuclear Plant on April 15-18, 2002. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening processes in accordance with the methodologies described in the LRA.

The staff conducted an inspection on October 21-25, 2002, of the results associated with the process of scoping and screening plant structures and components that are subject to aging management reviews. The inspection determined that the documentation of the scoping and screening process was of good quality, detailed, thorough, and understandable.

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application—Technical Information," requires that each application for license renewal contain an IPA. Furthermore, the IPA must list and identify those structures and components that are subject to an aging management review (AMR) from the structures, systems, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4.

In Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant describes the scoping and screening methodology used to identify SSCs at St. Lucie Units 1 and 2 that are within the scope of license renewal, and structures and components (SCs) that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine if it meets the scoping requirements stated in 10 CFR 54.4(a) and the screening requirements stated in 10 CFR 54.21.

In developing the scoping and screening methodology for the St. Lucie Units 1 and 2 LRA, the applicant considered the requirements of the rule (i.e., 10 CFR Part 54), the statement of consideration for the rule, and the guidance provided by the Nuclear Energy Institute (NEI) in NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," Revision 3, issued in March 2001. In addition, the applicant also considered the NRC staff's correspondence with the NEI and other applicants concerning the development of this methodology.

2.1.2 Summary of Technical Information in the Application

In Sections 2.0 and 3.0 of the LRA, the applicant provides the technical information required by 10 CFR 54.21(a). In Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant describes the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a), as well as the process used to identify the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

Additionally, Section 2.2, "Plant Level Scoping Results," Section 2.3, "System Scoping and Screening Results–Mechanical Systems," Section 2.4, "Scoping and Screening Results–Structures," and Section 2.5, "Scoping and Screening Results–Electrical and Instrumentation and Controls (I&C) Systems," of the LRA amplify the process that the applicant uses to identify the SCs that are subject to an AMR. Chapter 3 of the LRA, "Aging Management Review Results," contains Section 3.1, "Reactor Coolant System"; Section 3.2, "Engineered Safety Features Systems"; Section 3.3, "Auxiliary Systems"; Section 3.4, "Steam and Power Conversion Systems"; Section 3.5, "Structures and Structural Components"; and Section 3.6, "Electrical and Instrumentation and Control." Chapter 4 of the LRA, "Time-Limited Aging Analyses," contains the applicant's evaluation of time-limited aging analyses.

2.1.2.1 Application of the Scoping Criteria in 10 CFR 54.4(a)

In Section 2.1.1.2 of the LRA, the applicant discusses the scoping methodology as it relates to the safety-related criteria, in accordance with 10 CFR 54.4(a)(1). With respect to the safety-related criteria, the applicant states that the SSCs within the scope of license renewal include safety-related SSCs, which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following intended functions.

- the integrity of the reactor coolant pressure boundary
- the capability to shut down the reactor and maintain it in a safe shutdown condition
- the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable

Note that the applicant has not revised the current accident source term for St. Lucie Units 1 and 2; therefore, the requirements of 10 CFR 50.67(b)(2) do not currently impact the license renewal program.

The applicant initially relied on the plant component database, which identified the quality list of safety-related and non-safety-related (Q-list) components, to identify safety-related SCs credited with remaining functional during and following design-basis events defined in the current licensing basis. These design-basis events (DBEs) encompass design-basis accidents, anticipated operational occurrences, natural phenomena, and external events. Additional scoping activities were then performed using two distinct efforts to identify systems and structures within the scope of license renewal. Additional design-basis documents, licensing correspondence, and design drawings were reviewed to establish which SSCs were within scope and to identify which intended functions for each system and structure were within scope.

In Section 2.1.1.3 of the LRA, the applicant discusses the scoping methodology as it relates to the non-safety-related criteria, in accordance with 10 CFR 54.4(a)(2). With respect to the non-safety-related criteria, the applicant states, in part, that a review was performed to identify the non-safety-related SSCs whose failure could prevent satisfactory accomplishment of the safety-related intended functions identified in 10 CFR 54.4(a)(1). The review considered two categories of potential SSCs.

(1) non-safety-related SSCs that functionally support the operation of safety-related SSCs

(2) non-safety-related SSCs whose failure could cause an interaction with safety-related SSCs and potentially result in the failure of the safety-related SSCs to perform their intended safety function(s)

For the first category, the applicant conservatively assumed that non-safety-related piping and supports beyond the safety-related/non-safety-related boundary meet the 10 CFR 54.4(a)(2) criterion and are within scope. For the second category, the applicant performed a systematic review of potential non-safety-related/safety-related interactions. These interactions included high-energy pipe breaks, moderate-energy pipe breaks, and interaction of seismically supported non-safety-related systems with safety-related SSCs. As a result of the review, the applicant brought certain design features, such as piping supports, pipe whip restraints, and internal barriers, as well as certain non safety-related piping segments and structures, within the scope of license renewal, in accordance with regulatory requirements.

In Section 2.1.1.4 of the LRA, the applicant discusses the scoping methodology as it relates to the regulated event criteria, in accordance with 10 CFR 54.4(a)(3). With respect to the scoping criteria related to 10 CFR 54.4(a)(3), the applicant reviewed all SSCs relied on in safety analyses or plant evaluations to perform an intended function that demonstrates compliance with the Commission's regulations for fire protection (FP) (10 CFR 50.48), environmental qualification (EQ) (10 CFR 50.49), pressurized thermal shock (PTS) (10 CFR 50.61), anticipated transients without scram (ATWS) (10 CFR 50.62), and station blackout (SB0) (10 CFR 50.63) to ensure that they were adequately accounted for in the scoping methodology. To support this review, the applicant assembled and evaluated source documentation developed as part of the applicant's initial response to these specific requirements, including sections from St. Lucie, Units 1 and 2, updated final safety analysis reports (UFSARs), design-basis documents (DBDs), design drawings, component databases, and docketed correspondence, including regulatory commitments to the NRC to address each requirement.

Additionally, the applicant evaluated specific topical source information pertaining to each regulated event, including FP evaluation reports, safe shutdown analyses (SSAs), essential equipment lists, and EQ lists. These source documents contain detailed design information for each regulated event and provided an additional source of information to identify SCs credited for mitigation of the events of interest. In summary, the SSCs relied on in safety analyses or plant evaluations to perform an intended function that demonstrates compliance with NRC regulations for FP, EQ, PTS, ATWS, and SBO have been included in the scope of license renewal, in accordance with the criteria of 10 CFR 54.4(a)(3).

2.1.2.2 Documentation Sources Used for Scoping and Screening

In Section 2.1.1.1 of the LRA, the applicant describes the relevant technical information sources used to identify the safety-related and non-safety-related intended functions for which the plant has been designed. These sources were also used to develop the list of SSCs subject to an AMR.

The applicant developed a set of DBDs to provide a source of design basis information about selected plant systems. The DBDs are a tool to explain the requirements behind the design, rather than describing the design itself. Twenty-one DBD volumes were developed for each St. Lucie unit. This includes DBDs for 20 support and accident mitigation systems, and one DBD on selected licensing issues. The DBDs include the following information of importance to scoping and screening.

- system descriptions
- references to applicable DBDs (such as design changes and calculations) associated with the system
- a list of safety-related system intended functions, intended functions potentially meeting the non safety-related/safety-related criterion, and intended functions associated with FP, EQ, ATWS, PTS, and SBO

The PassPort Component Database includes specific component information for SSCs that can be found in the controlled component database. The controlled component database contains as-built information on a component level. The component database consists of multiple data fields for each component, such as design-related information, safety and seismic classifications, and component tag, type, and description.

The piping and instrumentation drawings (P&IDs) are schematic-type drawings that have been created for every significant plant piping system and several ventilation systems. The P&IDs provide valve, damper, piping, ductwork, instrumentation, and other component information. With respect to license renewal scoping, the P&IDs were used to identify seismic Class I boundaries and quality group classifications and boundaries, which are delineated on the P&IDs. The seismic and quality group classifications indicated on P&IDs are also described in each unit's UFSAR.

2.1.2.3 Scoping Methodology

The applicant utilized the scoping methodology to identify the plant systems, structures, and components that were within the scope of the license renewal rule. The applicant performed the scoping of SSCs as two separate efforts. A discussion of each effort is presented below.

2.1.2.3.1 Mechanical Systems and Civil Structures Scoping Methodology

The process used by the applicant to identify mechanical systems and civil structures in scope was based on initially establishing evaluation boundaries for each system. For mechanical systems, these evaluation boundaries were determined by mapping the pressure boundary associated with the license renewal system's intended functions onto the system flow diagrams. The system SCs that are within the scope of license renewal (i.e., required to perform a license renewal system intended function) are then identified. For these in-scope SCs, component intended functions are then identified. These component intended functions are based on the guidance provided in NEI 95-10.

For civil structures, the evaluation boundaries were determined by a review of design drawings, the structure component list from the component database, and plant walkdowns. SCs that are included within the structure were initially identified. These SCs include items such as walls, supports, and non-current-carrying electrical/I&C components (i.e., conduit, cable trays, electrical enclosures, instrument panels, and related supports). The SCs that are within the scope of license renewal (i.e., required to perform a license renewal system intended function) are then identified. Design features and associated SCs that prevent potential seismic interactions for in-scope structures that house both safety-related and non safety-related systems are also identified. This was accomplished by performing a walkdown of each plant area containing both safety-related and non safety-related SSCs. Like the mechanical structures and components, the structural component intended functions for in-scope SCs were identified based on the guidance provided in NEI 95-10 report.

2.1.2.3.2 Electrical and I&C Systems Scoping Methodology

The process used by the applicant to identify electrical and I&C systems in scope was based on initially establishing component commodity groups. The applicant stated, in part, that the primary difference in this method versus the one used for mechanical systems and structures is the order in which the component scoping and screening steps are performed. This method was selected for use with the electrical/I&C components since most electrical/I&C components are considered to be active. Thus, the method selected provides the most efficient means for determining electrical/I&C components that require an AMR. The method employed consisted of initially identifying electrical/I&C component commodity groups within the scope of license renewal. This was accomplished by a complete review of design drawings and electrical/I&C component commodity groups in the component database. For each commodity group, both a description and intended functions are identified from a review of pertinent design information.

2.1.2.4 Screening Methodology

Following the determination of SSCs within the scope of license renewal, the applicant implemented a process for determining which SCs, from the SSCs within the scope of renewal, would be subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1). In Section 2.1.2 of the LRA, the applicant discusses these screening activities as they relate to the SSCs that are within the scope of license renewal. The specific screening activities for the various engineering disciplines are further described in Section 2.1.2.1 for mechanical components, Section 2.1.2.2 for civil structures, and Section 2.1.2.3 for electrical/I&C systems of the LRA.

2.1.2.4.1 *Mechanical System Screening*

The applicant states that the mechanical screening process was implemented for each of the systems that were identified during the scoping review phase to identify the passive mechanical components that support one or more of the system's intended functions. The system's intended functions, in conjunction with component information in the PassPort Component Database, pertinent design information related to the 10 CFR 54.4 (a)(2) and 10 CFR 54.4(a)(3) evaluations, and the applicable system drawings, were used to identify the passive components within the scope of license renewal. The screening criteria applied to this effort included identifying passive components in accordance with 10 CFR 54.21(a)(1)(i) and the guidance in NEI 95-10 and other industry guidance. Specifically, the in-scope SCs that perform an intended function without moving parts, or without a change in configuration or properties (i.e., screening criterion of 10 CFR 54.21(a)(1)(i)), were identified. These active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10. The passive, in-scope SCs that are not subject to replacement, based on a qualified life or specified time period (i.e., screening criterion of 10 CFR 54.21(a)(1)(ii)), were identified as requiring an AMR. The determinations of whether passive, in-scope SCs have a qualified life or specified replacement time period were based on the review of plant-specific information, including the PassPort Component Database, maintenance programs and procedures, vendor manuals, and plant experience. The in-scope SCs identified as requiring an AMR were then compared to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," to ensure that differences were valid and justified.

Following the completion of the screening review for a system, the passive mechanical components within the scope of license renewal were identified and compiled in a screening results report, which contains pertinent information on the system design, intended functions, components of interest, and relevant aging management evaluation information.

2.1.2.4.2 *Civil/Structural Screening*

After identifying the SSCs that were within the scope of license renewal, the applicant performed the following screening review to determine which SCs would be subject to an AMR.

The structural components within the scope of 10 CFR Part 54 were reviewed to determine which of the components should be subjected to an AMR, in accordance with 10 CFR 54.21(a)(1). An AMR of a structural component is required if the component performs an intended function without moving parts, or without a change in configuration or properties (i.e., passive), and if it is not subject to replacement on the basis of a qualified life or specified time period (i.e., long-lived).

For the purposes of the LRA screening process, screening was performed for each structure that had been identified as being within the scope of license renewal. The purpose of civil/structural screening was to identify the types of passive structural members (walls, beams, floors, grating, block walls, missile shields, pads, liners, etc.) that support the intended function(s) of the structure and, therefore, require an AMR. The types of structural members that require an AMR were identified based upon a review of the structural detail drawings and plant walkdowns. For uniquely identified structural members, the data in the PassPort Component Database were also reviewed.

The structural screening process was similar to that used for the mechanical systems and consisted of initially identifying the in-scope SCs that perform an intended function without moving parts, or without a change in configuration or properties (i.e., screening criterion of 10 CFR 54.21(a)(1)(i)). These active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10. The passive, in-scope SCs, which were not subject to replacement based on a qualified life or specified time period (i.e., screening criterion of 10 CFR 54.21(a)(1)(ii)), were identified as requiring an AMR. The determinations of whether passive, in-scope structural SCs have a qualified life or specified replacement time period were based on the review of plant-specific information, including the component database, maintenance programs and procedures, vendor manuals, and plant experience. The applicant also compared the in-scope structural SCs identified as requiring an AMR to the results of the GALL Report and ensured that any differences were validated and justified.

2.1.2.4.3 Electrical and I&C System Screening

After identifying the SSCs that were within the scope of license renewal, the applicant performed the following screening review to determine which electrical components would be subjected to an AMR. As part of this effort, the applicant relied on the requirements contained in 10 CFR 54.21(a)(1)(i), and the industry guidance contained in NEI 95-10, to develop a commodity evaluation approach that relies on a plant-level evaluation of electrical equipment. The majority of electrical/I&C component groups (e.g., transmitters, switches, breakers, relays, actuators, radiation monitors, recorders, isolators, signal conditioners, meters, batteries, analyzers, chargers, motors, regulators, transformers, and fuses) are considered active, in accordance with 10 CFR 54.21(a)(1)(i) and the guidelines in NEI 95-10, and therefore do not require an AMR.

The applicant identified that passive electrical/I&C component commodity groups, which are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)), require an AMR. Electrical/I&C component commodity groups covered by the 10 CFR 50.49 Environmental Qualification Program were considered to be subject to replacement, based on qualified life. Certain passive, long-lived electrical/I&C component commodity groups that do not support license renewal system intended functions were eliminated. The applicant compared the in-scope SCs identified as requiring an AMR to the results of the GALL Report to ensure that differences were validated and justified.

2.1.3 Staff Evaluation

As part of the review of the applicant's LRA, the NRC staff evaluated the scoping and screening activities described in the following sections of the application.

- Section 2.1, "Scoping and Screening Methodology," to ensure that the applicant describes a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3)
- Section 2.2, "Plant Level Scoping Results"
- Section 2.3, "Scoping and Screening Results—Mechanical Systems"
- Section 2.4, "Scoping and Screening Results—Structures"

- Section 2.5, "Screening Results—Electrical and Instrumentation and Controls (I&C) Systems"

In addition, the staff conducted a scoping and screening methodology audit at the St. Lucie site from April 15—18, 2002. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the application and the requirements of the rule. The audit team reviewed implementation procedures and engineering reports that describe the scoping and screening methodology implemented by the applicant. In addition, the audit team conducted detailed discussions with the cognizant engineers on the I&C of the program, reviewed administrative control documentation, and selected design documentation used by the applicant during the scoping and screening process. The audit team further reviewed a sample of system scoping and screening results reports to ensure that the methodology outlined in the administrative controls was appropriately implemented and that the results reports were consistent with the current licensing basis (CLB) as described in the supporting design documentation.

2.1.3.1 Scoping Methodology

The audit team reviewed implementation procedures and engineering reports (outlined below) which describe the scoping and screening methodology implemented by the applicant.

- ENG-QI 5.3, Rev. 4, "License Renewal System/Structure Scoping"
- ENG-QI 5.4, Rev. 3, "License Renewal Screening"
- PSL-ENG-LRSP-00-030, Rev. 2, "License Renewal System/Structure Scoping Report—St. Lucie Unit 1—Florida Power and Light Company"
- PSL-ENG-LRSP-00-031, Rev. 2, "License Renewal System/Structure Scoping Report—St. Lucie Unit 2—Florida Power and Light Company"
- PSL-ENG-LRSC-00-050, Rev. 2, "License Renewal Screening Results for Structures and Structural Components"
- PSL-ENG-LRSC-00-052, Rev. 1, "License Renewal Screening Results for Electrical/I&C Component Commodity Groups"

The team determined that the scoping and screening methodology reports and procedures were consistent with Section 2.1 of the LRA and were of sufficient detail to provide the applicant's staff with concise guidance on the scoping and screening implementation process to be followed during the LRA activities. In addition to the implementing procedures, the audit team reviewed supplemental design information including DBDs, system drawings, and selected licensing documentation, which the applicant relied during the scoping and screening phases of the review. The team found these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the CLB of the St. Lucie plants.

As part of the audit, the applicant further described the process used to incorporate plant design information into the LRA development process. The applicant referenced ENG-QI 5.3, Revision 4, "License Renewal System/Structure Scoping," and ENG-QI 5.4, Revision 3, "License Renewal Screening," to describe the detailed process for developing the LRA application. To accomplish license renewal scoping, the applicant's engineering instructions incorporated the principle of identifying a traceable record of the scoping by using existing plant documentation to identify systems and structures within the scope of the license renewal rule.

Specifically, documentation that the applicant used for the scoping reviews included the UFSAR, technical specifications, and documents comprising the St. Lucie CLB. Additional source documents included the DBDs, controlled drawings, and the controlled component list in the PassPort Component Database. The applicant's engineering staff was cognizant of the requirements for and use of these information sources during the scoping development phase of the LRA project.

The applicant provided the audit team with a detailed description of the system DBDs and described how they were incorporated into the scoping and screening process. The DBDs were developed by the applicant during the design configuration documentation project. The audit team reviewed a sample of the DBDs for both safety-related and non safety-related systems to better understand the approach the applicant implemented to determine which SSCs would be initially placed in scope for license renewal. The team found that the DBDs provide a concise, well-documented discussion of the system, including safety-related, non safety-related, and NRC-required functions (i.e., functions which had been identified as a result of commitments to the NRC, including those for the NRC regulations identified under 10 CFR 54.4 (a)(3)). Additionally, each DBD identifies any function of the system relied upon for the five regulated events. Included in each DBD was a detailed list of the sources of information, which included St. Lucie specific sources, such as the UFSAR, technical specifications, calculations, and analyses, as well as non-plant-specific sources, such as industry codes and standards, NUREGs, regulatory guides, inspection and enforcement bulletins (IEBs), notices, generic letters, and Commission orders. The DBD documentation is controlled and maintained in accordance with the applicant's Site Quality Assurance Program governed by ENG-QI 3.0, Revision 4, "Quality Assurance Records." The audit team reviewed the governing procedures and administrative controls and determined that they presented adequate guidance for the preparation, control, and maintenance of the DBDs.

The applicant also provided the audit team with a detailed discussion on the development of the St. Lucie Units 1 and 2 system scoping reports (PSL-ENG-LRSP-00-30, Revision 2, and PSL-ENG-LRSP-00-31, Revision 2 respectively). The applicant's engineering staff developed these reports to ensure that SSCs within the CLB, which address the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3), were identified and considered for inclusion in the scope of the LRA.

With respect to the information used to scope 10 CFR 54.4(a)(1) safety-related SSCs, the applicant's process described in procedure ENG-QI 5.3, Revision 4 requires that the DBDs, UFSARs, and the PassPort Component Database system be searched to identify systems and structures that meet the safety-related criteria. As part of the audit team review of the Q-list implementation, the team reviewed a sample of the database search results tables developed by the applicant to support the LRA program. The applicant designed a series of filters which enabled the LRA review engineers to sort through the equipment data system records and provide concise tables of component records on the basis of safety classification or specific intended functions of interest, such as EQ and FP. The audit team determined that the filter process was a useful tool for the applicant in developing the initial scope of SSCs for the program.

With respect to the scoping of the 10 CFR 54.4(a)(2) SSCs, the applicant developed detailed guidance for evaluating potential non safety-related SSCs affecting safety-related SSCs. The applicant's scoping procedure provides for two methods of identifying potential 10 CFR 54.4(a)(2) SSCs, a system/structure-based approach and a component/spaces approach. The sources of information the applicant used to review and identify these 10 CFR 54.4(a)(2) SSCs included interpretation of guidelines to be considered during the application of the 10 CFR 54.4(a)(2) requirements, description of interactions and events, description of mitigative and support functions, and a summary of potential interactions of certain operational occurrences, such as flooding and high-energy line breaks.

The applicant's 10 CFR 54.4(a)(3) scoping process requires identification of source documents used to provide evaluations for demonstrating compliance with each of the regulated events of interest in accordance with the regulations. The applicant's evaluations focused on identifying and verifying that specific systems or structures were relied upon in response to the particular regulated event. In this evaluation, the applicant identifies the function which is credited or assumed to occur for each of the events. Specific documents that the applicant reviewed for evaluating the regulated events are listed below.

- 10 CFR 50.48—Fire Protection Evaluation Report, UFSAR, DBDs, and docketed correspondence to regulatory commitments to the NRC that address FP regulations

- 10 CFR 50.49—Environmental Qualification List and docketed correspondence to regulatory commitments to the NRC on EQ

- 10 CFR 50.61—docketed correspondence to regulatory commitments to the NRC that address NRC regulations on PTS and the reactor vessel UFSAR section

- 10 CFR 50.62—docketed correspondence to regulatory commitments to the NRC on ATWS and the UFSAR

- 10 CFR 50.63—docketed correspondence to regulatory commitments to the NRC on SBO and the UFSAR and DBDs

Following the completion of the identification of the systems or structures included in the scope of license renewal, the applicant listed the system and structure intended functions that were the basis for including the system/structure in the scope. Structures specifically identified using the component/spaces scoping process to satisfy the 10 CFR 54.4(a)(2) requirement were listed by the type of interaction that non safety-related/safety-related equipment would potentially have in lieu of providing specific intended functions. The audit team reviewed the completed Unit 1 and Unit 2 scoping results and verified that the applicant had adequately incorporated the results of these efforts into the scoping methodology reports. However, as part of this review, the audit team determined that additional activities were required by the applicant to address the 10 CFR 54.4(a)(2) requirements, as specified in the interim staff guidance on the subject. Additionally, the audit team requested the applicant to evaluate the interim staff guidance issued on April 1, 2002, related to the scoping of SSCs to meet the requirements of the SBO rule.

With regard to the scoping of SSCs to meet the requirements of 10 CFR 54.4(a)(2), the audit team discussed the current interim staff guidance on the 54.4(a)(2) issue with the applicant. The staff noted that by letters dated December 3, 2001, and March 15, 2002, respectively, the NRC issued a staff position to the NEI which described areas to be considered, and options it expects licensees to use to determine what SSCs meet the 10 CFR 54.4(a)(2) criterion (i.e., non safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i), (ii), and (iii) of 10 CFR 54.4).

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

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

Consistent with the staff position described in the aforementioned letters, the audit team requested that the applicant respond to RAI 2.1-1 which was sent to the applicant in a letter dated July 1, 2002. In the RAI, the staff specifically asked the applicant to describe its scoping methodology implementation for the evaluation of the 10 CFR 54.4(a)(2) criterion. As part of the response, the staff requested that the applicant indicate the option(s) credited, list the SSCs included within scope, list those SCs for which AMRs were conducted, and for each SC, identify the applicable aging management programs (AMPs) credited for managing the identified aging effects.

By letter dated September 26, 2002 (FPL Letter No. L-2002-139), the applicant responded to the staff's request for information. In that response, the applicant reiterated those SSCs, including mitigative design features, included within the scope of license renewal as a result of its initial evaluation. The SSCs listed below were initially in scope.

- non safety-related piping segments and supports at safety-related/non safety-related functional boundaries which extend beyond the system pressure boundary component to ensure the integrity of the safety-related/non safety-related functional system pressure boundary (LRA Tables 3.5-1 through 3.5-16)

- piping/component supports for non safety-related mechanical systems with the potential of "seismic II over I" interaction with safety-related components (LRA Tables 3.5-1 through 3.5-16)

- non safety-related conduit, cable trays, supports, and other structural components with the potential of "seismic II over I" interaction with safety-related components (LRA Tables 3.5-1 through 3.5-16)

- design features required to accommodate the effects of flooding, such as curbing, platforms, sumps, sump pumps, and drains (LRA Tables 3.5-1 through 3.5-16, Table 3.3-13, and Table 3.3-16)

- design features required to accommodate the effects of spray, jet impingement, and pipe whip, such as pipe whip restraints and internal barriers (LRA Tables 3.5-1 through 3.5-16)

The applicant further stated that the approach for scoping of "seismic II over I" is dependent upon the location of non safety-related systems or structures relative to the safety-related systems and structures. As a result, the applicant stated that an area-based approach for scoping of "seismic II over I" was chosen. This approach identified the major structures of the plant containing both safety-related and non safety-related components and structural components. These major structures included containments, component cooling water areas, condensate storage tank enclosures, diesel oil equipment enclosures, emergency diesel generator (EDG) buildings, fuel handling buildings, intake structures, reactor auxiliary buildings (RABs), steam trestle areas, turbine building (Unit 1 only), ultimate heat sink dam, and yard structures. Based on the initial identification of these structures, the applicant then established the specific non safety-related seismic interaction component or structural component types located within the structure for inclusion in the license renewal scope.

The applicant stated that the review for seismic, leakage, pipe rupture, and other interactions of non safety-related components and structural components that could potentially affect safety-related SCs included both non safety-related piping systems that are connected to safety-related piping systems, as well as non safety-related piping systems that are not connected to safety-related piping systems. This review considered the CLB for St. Lucie Units 1 and 2 in establishing seismic, leakage, pipe rupture, and other interactions. Those items determined to have an interaction were included in the scope of license renewal, and AMRs were performed and summarized in the LRA.

The applicant further addressed the staff's concerns regarding the potential for age-related degradation of non-safety-related SSCs that could affect safety-related SSCs raised during the audit by performing a supplemental review to establish what additional non-safety-related SSCs should be included in the scope of license renewal. This supplemental review included six steps.

(1) A review of industry and plant-specific operating history of non safety-related piping and components containing air/gas was performed to determine whether these components required further consideration with regard to interactions with safety-related components.

(2) For each of the major structures of the plant containing both safety-related and non safety-related components and structural components, non safety-related piping systems containing fluid and/or steam were identified. This included both high-energy and other piping.

(3) If the identified non safety-related piping was in the scope of license renewal to address the other scoping criteria of 10 CFR 54.4(a), no additional evaluation of this piping was required since an AMR has already been performed, and appropriate AMPs have been identified to ensure intended functions are maintained. These AMRs and AMPs are included in the LRA.

(4) All remaining non safety-related piping from the completion of Steps 1, 2, and 3 above was then assumed to fail anywhere along its length.

(5) On the basis of the assumed failures from Step 4 and a review of design drawings and plant walkdowns, the effects of pipe whip, jet impingement, physical contact (i.e., piping

falling such that it physically contacts safety-related equipment), leakage, and/or spray were evaluated to determine if these interactions could potentially impact safety-related component functions. Specifically, the effects of pipe whip, jet impingement, and physical contact were considered for all non safety-related high-energy piping, and the effects of spray and leakage were considered for all other non safety-related piping. High energy, as used in this evaluation, includes high-energy and moderate-energy systems defined by the St. Lucie Units 1 and 2 CLBs. This definition encompasses systems operating at conditions of >200 °F or >275. If the effects of these interactions were determined to impact safety-related component functions, the non safety-related piping and its associated components were identified as being within the scope of license renewal. If there was no impact on safety-related component functions as a result of the effects of these assumed failures, the piping was determined not to meet the scoping criteria of 10 CFR 54.4(a)(2) and thus was not considered to be within the scope of license renewal.

(6) If the piping and associated components were determined to be within the scope of license renewal, an AMR evaluation was performed on these components, based on AMRs performed on components of the same material exposed to the same internal and external environments.

With respect to the non-fluid-filled piping systems, the applicant performed a review of NRC generic communications and industry operating experience associated with non safety-related piping/ductwork and components containing air/gas (i.e., heating, ventilation, and air conditioning (HVAC); hydrogen; nitrogen; instrument air; etc.). This review did not reveal any instances of collapse or significant failures of piping/ductwork and components due to aging. Review of plant-specific operating experience associated with non safety-related piping/ductwork and components containing air/gas also did not identify any instances of collapses or significant failures of piping/ductwork and components due to aging. As a result, other than the supports for non safety-related piping/ductwork and components associated with systems containing air/gas, which have already been included in the scope of license renewal in the areas with the potential for interaction with safety-related components, no further SSCs were brought into scope for air/gas systems.

For systems containing fluid and/or steam, each major structure of the plant containing both safety-related and non safety-related components and structural components was evaluated based on the criteria described in Step 5 above. As part of its review of the implementation and results of these activities, the staff performed a license renewal scoping and screening inspection on October 21–25, 2002. The inspectors reviewed the applicant's engineering evaluation and documentation of the portions of the systems added to scope, selected layout markup drawings, and discussed the process with the cognizant individuals responsible for the evaluations. Additionally, the NRC inspectors performed a walkdown of selected areas of the plant containing SSCs added to scope and areas which were unaffected by the licensee's supplemental review. The inspection team determined that the applicant's implementation of the supplementary evaluation was comprehensive, and the inspectors did not identify any additional equipment which should have been included in scope to meet the 10 CFR 54.4(a)(2) requirement.

The staff has reviewed the applicant's supplemental evaluation and finds it to be acceptable on the basis of the applicant's inclusion of additional non safety-related SSCs which meet the 10 CFR Part 54.4(a)(2) requirements using the revised methodology. As a result of this supplemental review, the applicant brought portions of additional non safety-related systems and associated components into the scope of license renewal, supplied the results of the associated AMRs, and presented a summary of the programs and activities that will be used to manage aging of these SCs. The staff's evaluation of the applicant's scoping and screening results and aging management reviews of SCs in these systems is presented in Sections 2.3.5 and 3.3.17.7 of this SER, respectively.

The applicant supplied additional information concerning the (1) expansion of the systems within the scope of license renewal and addition of new portions of systems within scope as a result of the revised methodology, (2) determination of the credible failures which could impact the ability of safety-related SSCs from performing their intended functions, (3) evaluation of relevant operating experience, and (4) incorporation of identified non safety-related SSCs into the applicant's AMPs, and (5) results of NRC inspection and audit activities. On the basis of this additional information, the staff concludes that the applicant has supplied sufficient information to demonstrate that all SSCs that meet the 10 CFR 54.4(a)(2) scoping requirements have been identified as being within the scope of license renewal. Therefore, RAI 2.1-1 is considered resolved.

The second scoping issue associated with the SSCs is related to SBO. The audit team requested that the applicant respond to RAI 2.1-2, which was sent to the applicant in a letter dated July 1, 2002. The RAI requested the applicant to (1) describe the process used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3), (2) list those additional SSCs included within scope as a result of its efforts, (3) list those structures and components for which AMRs were conducted, and (4) describe (as applicable for each structure or component) the AMRs that will be credited for managing the identified aging effects.

By letter dated September 26, 2002 (FPL Letter No. L-2002-139), the applicant responded to the staff's request for information. In that response, the applicant stated that the scoping of SSCs to meet the SBO requirements was conducted by performing an evaluation of the design documentation associated with SBO for the units. This design information includes Unit 1 UFSAR Section 15.2.13, Unit 2 UFSAR Section 15.10, and licensing correspondence between FPL and the NRC to initially resolve the SBO requirements. On the basis of these references, the applicant determined that 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 EDGs, 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.

The applicant contends that it does not rely on the restoration of offsite power to meet the requirements of the SBO rule for St. Lucie Units 1 and 2. However, the applicant performed a supplemental evaluation to determine the additional electrical and structural components that are in the scope of license renewal for restoration of offsite power. For those electrical and structural components determined to be within the scope of license renewal, the applicant performed AMRs that were included in its response to RAI 2.1-2. The staff's review of the applicant's scoping results and aging management evaluation of SCs related to this issue is presented in Sections 2.5.2.1.1 and 3.6.4 of this SER, respectively.

The applicant provided information concerning the identification of relevant design documentation, including site and industry operating experience, and subsequent expansion of the scope of electrical equipment considered within scope of the license renewal as a result of the revised SBO methodology. On the basis of the additional information supplied by the applicant, the staff finds the applicant's revised methodology to be an acceptable approach for identifying those additional SSCs which should be considered within scope to address the SBO issue. Therefore, RAI 2.1-2 is considered resolved.

On the basis of the evaluation described above, the audit team determined that the methodology implemented by the applicant, as described in the LRA and supplemental responses to staff's RAIs, is consistent with the requirements of the rule and that the scoping methodology will identify SCs that meet the screening criteria of 10 CFR 54.4(a)(1—3).

2.1.3.2 Screening Methodology

Evaluation of Methodology for Identifying Structures and Components Subject to an Aging Management Review. The audit team reviewed the methodology used by the applicant to identify mechanical, structural, and electrical components within the scope of license renewal that would be subject to further aging management evaluation. The applicant provided the staff with a detailed discussion of the processes used for each discipline and provided technical reports that described the screening methodology, as well as a sample of the screening results reports for a selected group of safety-related and non safety-related systems. The applicant referenced ENG-QI 5.4, Revision 3, "License Renewal Screening," during the review of the screening process. This procedure was used to establish the applicant's screening methodology requirements and to establish requirements for developing screening results summary reports. These screening results summary reports contain the record of the applicant's screening efforts to meet 10 CFR 54.37(a). The applicant's process followed the guidance provided in NEI 95-10. The applicant utilized two processes to identify those plant SCs that were within the scope of license and that require an AMR. These processes were a systems/structures-based approach and a component/spaces-based approach.

The applicant's system/structure-based approach is used by the applicant when identification of component/structures requiring an AMR is greatly dependent on system intended function. To accomplish this type of screening review, the applicant performs four evaluations:

(1) Identify SCs within the system/structure being screened.

(2) Define system/structure evaluation boundaries and eliminate systems/structures not required to perform the system/structure intended functions.

(3) Identify SCs that perform their intended functions in a passive manner to eliminate all active SCs.

(4) Identify long-lived SCs to eliminate all short-lived (replaceable) SCs.

The component/spaces-based approach is used by the applicant in cases where a system-based review is not conducive to the identification of components/structures requiring an AMR. To accomplish this type of screening review the applicant performs four evaluations.

(1) Define the specific plant design criteria associated with interaction design requirements shall (e.g., equipment interaction envelopes).

(2) Review plant design documentation to identify specific components/structures for which interaction design analyses or interaction studies have been performed.

(3) Perform a walkdown of each plant area containing both safety-related and non safety-related components/structures, as identified in the scoping phase, to identify specific components/structures or categories of components/structures which must meet interaction design requirements.

(4) Develop a list of components/structures or categories of components/structures requiring an AMR for each applicable plant area.

Mechanical Components. During the audit of the applicant's license renewal scoping and screening process conducted by the NRC staff, the audit team reviewed the methodology used by the applicant to identify and list the mechanical components subject to an AMR, as well as the applicant's technical justification for this methodology. The team also examined the applicant's results from the implementation of this methodology by reviewing a sample of the mechanical systems identified as being within the scope, the evaluation boundaries drawn within those systems on the P&IDs, the resulting components determined to be within the scope of the rule, the corresponding component-level intended functions, and the resulting list of mechanical components subject to an AMR.

The methodology for identifying mechanical components within the scope of the rule included both uniquely identified (i.e., components identified in the applicant's electronic component database) and nonuniquely identified components. For the uniquely identified components, the individual components were identified and reviewed. For the nonuniquely identified components, the components were categorized by component groups or commodities. These component groups were then evaluated as part of the system screening table development.

The audit team reviewed a sample of the mechanical system screening reports assembled by the applicant and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

Structures. During the audit of the applicant's renewal scoping and screening process, the staff also examined the applicant's results from the implementation of this methodology by reviewing the structural components identified as being within the scope, the corresponding structural-level intended functions, and the resulting list of structural components subject to an AMR. This information is detailed in PSL-ENG-LRSC-00-050, Revision 2, "License Renewal Screening Results Structures and Structural Components."

The applicant used the results of the system scoping process and identified all of the in-scope structures and structural components as the subject of the AMR screening, including buildings, enclosures, equipment pad, foundations, missile shields, structural steel, fire rated assemblies, conduits, cable trays, electrical supports, electrical enclosures, pipe supports, etc. The results of the structure and structural component scoping, documented in PSL-ENG-LRSC-00-050, included a list of 18 in-scope structures, areas, buildings, and structural commodity groups.

The applicant's screening process was then applied to this set of structures and commodity groups.

The applicant's process for structural component screening involved identifying components listed in the equipment data module for the individual structures. To this, the applicant added additional structural component types which were contained in the structure but not identified by component number. From this total list, the applicant removed components addressed in other screening documents. The components in this listing were then reviewed to determine which required an AMR.

The audit team reviewed a sample of the structural drawing packages assembled by the applicant, and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

Electrical Components. During the audit of the applicant's renewal scoping and screening process, the staff also evaluated the implementation of this methodology by reviewing the list of electrical components subject to an AMR described in PSL-ENG-LRSC-00-0052, Revision 1, "License Renewal Screening Results for Electrical/I&C Component Commodity Groups." To screen these electrical/I&C components, the applicant first started with the results of the system scoping. The applicant then developed a composite list of electrical/I&C commodity group items based on the license renewal lists provided in Appendix B of NEI 95-10, Revision 3, combined with St. Lucie-specific electrical/I&C components not given in the industry guidance. The St. Lucie-specific items were identified by reviewing St. Lucie-specific electrical and I&C drawings and by a computer search of the applicant's equipment data module of the PassPort Component Database. The applicant next identified the electrical/I&C component commodity group intended functions, screened for active functions of the commodity groups, screened for passive commodity groups, and then defined the commodity groups subject to an AMR. The results were reviewed by the audit team with the cognizant engineers responsible for the review. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

System Screening Results. The applicant implemented a system-level screening process to identify mechanical, structural, and electrical components subject to an AMR. The system screening process included both the uniquely numbered and nonuniquely numbered components as stated above for each discipline. The system screening results reports contained the following information.

- system description and intended functions (including safety-related and non safety-related functions associated with the five regulated events, and other non-license renewal functions)
- system evaluation boundaries (containing boundary components and interfacing system information)
- system screening tables (containing a listing of all components within system and an indication of whether they are within scope, long-lived, and/or passive, and if an AMR is required)
- result table of system components requiring an AMR

These report development activities provided a mechanism to verify that system intended functions, on the basis of detailed system design documentation, were captured adequately, and that the components selected for further review supported those intended functions. The screening tables were further used in the system screening reports to document the individual system components and commodity groups for which AMRs were performed, as well as those components for which no AMR is needed. For each component, the screening table identified the license renewal scoping criteria (i.e., safety-related, non safety-related affecting safety-related, and the five regulated events) which were used to bring the component into scope.

The audit team reviewed the screening implementation procedures and a selected sample of the system screening reports to ensure consistent application of the applicant's screening methodology. The team identified that the sample reviewed was developed in accordance with the administrative controls governing the process and was consistent in level of detail and presentation. The audit team further reviewed a sample of the license renewal drawing and system screening table results to ensure that the individual components identified in the system screening tables were reflected appropriately on the drawings. The team did not observe any discrepancies between the sample tables and drawings evaluated.

On the basis of the evaluation described above, the audit team determined that the methodology, as described in the LRA and implemented by the applicant, is consistent with the requirements of the rule and that the screening methodology will identify SCs that meet the screening criteria of 10 CFR 54.21(a)(1).

2.1.4 Conclusions

The staff review of the information presented in Section 2.1 of the LRA, the supporting information in the UFSARs, the information presented during the scoping and screening audit, the scoping inspection, and the applicant's responses to the staff's RAIs formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology, including their supplemental 10 CFR 54.4(a)(2) review which brought additional non-safety-related piping segments and associated components into the scope of license renewal, was consistent with the requirements of the rule and the staff's position on the treatment of non-safety-related SSCs.

The staff concludes that there is reasonable assurance that the applicant's methodology for identifying SSCs within the scope of license renewal and the SCs requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 Plant-Level Scoping Results

2.2.1 Introduction

The applicant describes the process for identifying the SSCs within the scope of license renewal in Section 2.1 of the LRA. Using that scoping methodology, the applicant identified the SSCs that are within the scope of license renewal and the systems and structures that are not within the scope of license renewal. The applicant provided the results of its scoping review in Section 2.2 of the LRA, "Plant-Level Scoping Results." The staff reviewed Section 2.2 of the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified all plant-level SSCs that are relied upon to mitigate DBEs as required by 10 CFR

54.4(a)(1), or whose failure could prevent mitigation of DBEs, as required by 10 CFR 54.4(a)(2), as well as the SSCs relied on in safety analyses or plant evaluations to perform a function that is required by one of the regulations referenced in 10 CFR 54.4(a)(3).

2.2.2 Summary of Technical Information in the Application

2.2.2.1 Systems, Structures, and Components within the Scope of License Renewal

The SSCs that the applicant has determined to be within the scope of license renewal are listed in the LRA in Table 2.2-1, "License Renewal Scoping Results for Mechanical Systems," Table 2.2-2, "License Renewal Scoping Results for Structures," and Table 2.2-3, "License Renewal Scoping Results for Electrical/I&C Systems." The mechanical systems listed in Table 2.2-1 are described in Section 2.3 of the LRA. The structures listed in Table 2.2-2 are described in Section 2.4 of the LRA. The electrical and I&C components listed in Table 2.2-3 are described in Section 2.5. In regard to electrical and I&C systems, the applicant used a commodity group approach for the electrical and I&C components found to be within the scope of license renewal. In response to staff RAIs, the applicant brought into the scope of license renewal 2 formerly out-of-scope mechanical systems and 1 formerly out-of-scope structure, and added components for 11 of the mechanical systems already within the scope of license renewal as listed in Table 2.2-1 of the LRA.

Design Differences between Units 1 and 2. St. Lucie Unit 1 received its operating license March 1, 1976. St. Lucie Unit 2 received its operating license on April 6, 1983. As a result of the 7-year difference in plant age, changes occurred in the plant design and licensing bases which resulted in scoping and screening differences. The most widespread difference, in terms of the number of plant systems impacted, occurs in regards to SBO. Components relied upon for compliance with the SBO rule, 10 CFR 50.63, are specifically identified as being within the scope of the license renewal rule by 10 CFR 54.4(a)(3). St. Lucie Unit 1 is an alternate AC plant which credits use of either A or B train safety-related diesel generators from Unit 2. St. Lucie Unit 2 is a DC coping plant. Because of this difference in design approach, SBO support is an intended function for more Unit 1 systems and components than for Unit 2. For example, the Unit 1 turbine cooling water system is within the scope of license renewal because it has an intended function of cooling instrument air components relied upon during an SBO event.

A second major difference is in the area of ventilation system design. The Unit 1 control room air conditioning has three split-system air handling units, whose direct expansion refrigerant loops are housed both indoors and outdoors on the roof of the Reactor Auxiliary Building (RAB). The Unit 2 control room air conditioning system is housed completely indoors and is cooled by the component cooling water system. The Unit 1 computer room and hot shutdown panel are cooled by the miscellaneous ventilation system. This system does not exist at Unit 2; its intended functions are performed by the Unit 2 RAB electrical and battery room ventilation system. The Unit 2 fuel handling building ventilation system is within the scope of license renewal. The Unit 1 fuel handling building ventilation system is not in the scope of license renewal because it is not relied upon to mitigate the consequences of a fuel handling accident (FHA).

St. Lucie Unit 1 has a hydrogen purge system, while Unit 2 has a continuous containment/hydrogen purge system. There are a number of other design differences between the two units, which are discussed in specific sections of this SER.

2.2.2.2 Systems and Structures Not Within the Scope of License Renewal

The systems and structures that the applicant has determined not to be within the scope of license renewal are also listed in Tables 2.2-1, 2.2-2, and 2.2-3 of the LRA. Including the changes made in response to the staff's RAIs, 24 of the 50 mechanical systems listed in LRA Table 2.2-1 and 21 of the 46 structures listed in LRA Table 2.2-2 do not fall within the scope of license renewal.

2.2.3 Staff Evaluation

The staff reviewed Section 2.2, and specifically Tables 2.2-1, 2.2-2, and 2.2-3 of the LRA, to determine whether there is reasonable assurance that the applicant had appropriately identified plant-level SSCs that are within the scope of license renewal, as required by 10 CFR 54.4. The staff focused its review on verifying that the implementation of the applicant's methodology discussed in Section 2.1 of this SER did not result in the omission of SSCs from the scope of license renewal.

The staff used the UFSARs for St. Lucie Units 1 and 2 in performing its review. Pursuant to 10 CFR 50.34(b), the UFSARs contain descriptions and analyses of the SSCs of the facility, with emphasis upon performance requirements; the bases, with technical justification, upon which such requirements have been established; and the evaluations required to show that safety functions will be accomplished. The UFSARs are required to be updated periodically pursuant to 10 CFR 50.71(e). Thus, the UFSARs contain updated plant-specific licensing basis information regarding the SSCs and their functions.

The staff sampled the contents of the UFSARs, based on the listing of the systems and structures in Tables 2.2-1 and 2.2-2 of the LRA, to identify whether there are systems and structures that may have intended functions in accordance with the scoping requirements of 10 CFR 54.4 but were listed by the applicant as not within the scope of license renewal.

During its review, the staff determined that additional information was needed to complete its review. By letter dated July 18, 2002, the staff requested, in RAI 2.2-1, that the applicant provide a description of the air blower and sluice water systems. These two systems are listed in Table 2.2-1 of the LRA as not being within the scope of license renewal; however, descriptions of these systems and the functions they perform were not found in the UFSARs for St. Lucie Unit 1 or 2. In its response dated October 3, 2002, the applicant stated that both of these systems support the steam generator blowdown treatment facility demineralizer resin transfer process. Furthermore, the applicant stated that neither of these systems performs or supports any system intended function that satisfies the scoping criteria of 10 CFR 54.4(a). The staff finds the applicant's response to be acceptable because these systems are not safety-related or credited for any design-basis event and are not, therefore, within the scope of license renewal, as defined in 10 CFR 54.4(a).

By letter dated July 29, 2002, the staff requested, in RAI 2.2-2, that the applicant provide the basis for not listing miscellaneous drains as being within the scope of license renewal as presented in Table 2.2-1 of the LRA, although certain drains are credited in the flooding analysis presented in Section 3.6 of the Unit 2 UFSAR. The drains credited in the flooding analysis include the floor drains in the Unit 2 diesel generator building and the Unit 2 component cooling water area. In its response dated October 3, 2002, the applicant stated that the miscellaneous drains referred to in Table 2.2-1 are associated with the extraction steam system which is not within the scope of license renewal, and that most of the floor drains credited by the UFSAR flooding analysis are included in the scope of license renewal as part of the waste management system. The drain components associated with the waste management system are listed in Table 3.3-16 of the LRA. However, the specific floor drains in the Unit 2 diesel generator building and component cooling water areas cited by the RAI are not in the scope of license renewal. The applicant justified this omission by explaining that these areas can accommodate the maximum leakage anticipated from piping system failures in the structures without credit for the floor drains. Since the applicant explained that the diesel building and component cooling water area floor drains did not meet the scoping criteria for license renewal, the staff finds the applicant's response to be acceptable.

2.2.4 Conclusions

On the basis of its review of the information presented in Sections 2.2-1 and 2.2-2 of the LRA, the supporting information in the UFSARs for Units 1 and 2, and the information provided in response to RAIs, the staff concludes that there is reasonable assurance that the applicant has identified all SSCs appropriately whose intended functions meet the scoping and screening requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

2.3 System Scoping and Screening Results: Mechanical

This section addresses the staff's review of the results of the scoping and screening methodology for mechanical systems. The mechanical systems and their SCs are listed below.

Reactor Coolant Systems

- reactor coolant piping
- pressurizers
- reactor vessels (includes pressure boundary of control element drive mechanisms)
- reactor vessel internals
- reactor coolant pumps
- steam generators

Engineered Safety Feature Systems

- containment cooling
- containment spray
- containment isolation
- safety injection
- containment post-accident monitoring

Auxiliary Systems

- chemical and volume control system
- component cooling water
- demineralized makeup water (Unit 2 only)
- diesel generators and support systems
- emergency cooling canal
- fire protection
- fuel pool cooling

- instrument air
- intake cooling water
- miscellaneous bulk gas system
- primary water makeup
- sampling system
- service water
- turbine cooling water (Unit 1 only)
- ventilation
- waste management

Steam and Power Conversion Systems

- main steam, auxiliary steam, and turbine
- main Feedwater and steam generator blowdown
- auxiliary Feedwater and condensate

In accordance with the requirements stated in 10 CFR 54.21(a)(1), the applicant must identify and list structures and components subject to an AMR. These are passive, long-lived structures and components that are within the scope of license renewal. To verify that the applicant properly implemented its methodology, the staff reviewed the scoping and screening results to confirm that there was no omission of mechanical system components that are subject to an AMR.

2.3.1 Reactor Coolant Systems

In Section 2.3.1, "Reactor Coolant Systems," of the LRA for St. Lucie Units 1 and 2, the applicant described the SCs of the reactor coolant system (RCS) that are subject to an AMR for license renewal.

As described in the LRA, the RCS consists of the SCs designed to contain and support the nuclear fuel, contain the reactor coolant, and transfer the heat produced in the reactors to the steam and power conversion systems for the production of electricity.

Unless noted otherwise, the RCSs for St. Lucie Units 1 and 2 are the same, with no components common to both units. The RCSs are described in Unit 1 UFSAR Chapters 4 and 5 and Unit 2 UFSAR Chapters 4 and 5. This subsection includes the following component:

- reactor coolant piping
- pressurizers
- reactor vessels (includes pressure boundary of control element drive mechanisms)
- reactor vessel internals
- reactor coolant pumps
- steam generators

The license renewal flow diagrams listed in Table 2.3-1 of the LRA show the evaluation boundaries for the portions of the RCS that are within the scope of license renewal.

The RCS components subject to AMR include reactor vessels, control element drive mechanisms (pressure boundary only), pressurizers, steam generators, reactor vessel internals, reactor coolant pumps (RCPs) (pressure boundary only), piping, valves (pressure boundary only), and fittings.

Class 1, as used in the LRA, means the Safety Class 1 definition found in American National Standards Institute (ANSI) Standard N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

For St. Lucie Unit 1, the design code for reactor coolant piping is found in ANSI B31.7, Code for Nuclear Power Piping, Class 1, February 1, 1968, Draft Edition for Trial Use and Comment. For St. Lucie Unit 2, the design codes for reactor coolant piping are found in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, 1971 Edition through Winter 1972 Addenda, for nuclear steam supply system vendor-supplied reactor coolant piping, and the 1971 Edition through Summer 1973 Addenda, for architect-engineer supplied reactor coolant piping. The St. Lucie Units 1 and 2 pressurizer surge lines were reanalyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1986 Edition with no Addenda, in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification."

The pressurizers were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition through Winter 1967 Addenda, for St. Lucie Unit 1, and ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through Summer 1972 Addenda, for St. Lucie Unit 2.

The reactor vessels were manufactured by Combustion Engineering in accordance with the design and fabrication requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition through Winter 1967 Addenda, for St. Lucie Unit 1, and the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through Summer 1972 Addenda, for St. Lucie Unit 2. The control element drive mechanisms were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1968 Edition through Summer 1970 Addenda, for St. Lucie Unit 1, and the ASME Boiler and Pressure Vessel Code, Section III, 1974 Edition through Summer 1975 Addenda, for St. Lucie Unit 2.

The St. Lucie Unit 1 reactor vessel internals were designed before the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, for Core Support Structures was issued. However, a reanalysis of the core support barrel and the reactor internals without the thermal shield was performed following identification of core support barrel and thermal shield damage in 1983. The Unit 1 core support barrel repairs and thermal shield removal are discussed in Subsection 3.1.4.3.2 of the LRA, "Plant-Specific Operating Experience." The reactor vessel internals component stresses were evaluated during this reanalysis and found to be within the limits of the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, 1972 Draft Edition. The St. Lucie Unit 2 reactor vessel internals were designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, 1974 Edition, with the exception of stamping and a code stress report.

The RCP casings, main flanges, and main flange bolts were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition through Winter 1967 Addenda, for St. Lucie Unit 1, and the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through Summer 1973 Addenda, for St. Lucie Unit 2.

The original St. Lucie Unit 1 steam generators were replaced in 1997. The replacement steam generators were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1986 Edition with no addenda. The St. Lucie Unit 2 steam generators were designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through Summer 1972 Addenda.

2.3.1.1 Reactor Coolant Piping

2.3.1.1.1 Summary of Technical Information in the Application

Reactor coolant piping consists of piping (including branch connections, safe ends, flow restriction orifices, thermowells, and welds), pressure-retaining parts of valves, and bolted closures. Reactor coolant piping is described in the Unit 1 UFSAR, Section 5.5.6, and the Unit 2 UFSAR, Section 5.4.3. Reactor coolant piping is presented in the LRA in two parts, Class 1 piping and Non-Class 1 piping.

<u>Class 1 Piping</u>. Class 1 RCS piping components are within the scope of license renewal. The component intended functions of the in-scope Class 1 components include pressure boundary integrity and throttling. The following Class 1 reactor coolant components require an AMR.

- reactor coolant piping
- pressurizer surge, spray, safety, and relief piping and valves (pressure boundary only)
- reactor coolant pump lower seal heat exchangers and associated piping
- reactor coolant pump seal injection piping
- Class 1 flow restriction orifices
- thermowells
- reactor vessel head vent piping, fittings, and valves (pressure boundary only) upstream of the Class 1 flow restriction orifices
- vent, drain, and instrumentation lines upstream of Class 1 flow restriction orifices
- piping, fittings, and valves (pressure boundary only) associated with Class 1 portions of ancillary systems attached to the RCS including safety injection, sampling, and chemical and volume control

<u>Non-Class 1 Piping</u>. Several non-Class 1 RCS piping components are within the scope of license renewal. The component intended functions of the in-scope non-Class 1 components include pressure boundary integrity and throttling. The following non-Class 1 reactor coolant piping components require an AMR.

- instrumentation tubing, fittings, and valves (pressure boundary only) downstream of Class 1 flow restriction orifices

- vent and drain piping, tubing, fittings, and valves (pressure boundary only) downstream of Class 1 flow restriction orifices

- reactor vessel head vent piping, fittings, and valves (pressure boundary only) downstream of the Class 1 flow restriction orifices

- reactor coolant pump controlled bleed-off piping and orifices

The component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities for the reactor coolant piping are listed in Table 3.1-1 of the LRA. The component/commodity groups which were identified in the table include valves, piping/fittings, safe ends, nozzles, thermowells, restriction orifices, welds, bolting, and tubing/fittings. The intended functions identified were pressure boundary and throttling.

2.3.1.1.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the reactor coolant piping components and supporting structures within the scope of license renewal and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the reactor coolant piping and associated components and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a), and for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

On the basis of the information presented in Section 2.3.1.1 of the LRA and the associated sections of the UFSARs, the staff did not identify any omissions by the applicant.

2.3.1.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the reactor coolant piping components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.2 Pressurizers

2.3.1.2.1 Summary of Technical Information in the Application

The pressurizers are vertical cylindrical vessels containing electric heaters in the lower heads and water spray nozzles in the upper heads. The component intended functions of the pressurizers include pressure boundary integrity and pressurizer structural support. The pressurizers are described in the Unit 1 UFSAR, Section 5.5.2, and the Unit 2 UFSAR, Section 5.4.10.

Piping attached to the pressurizers is Class 1. Since piping with no intervening isolation valves interconnects sources of heat in the RCSs, overpressure protection for the RCSs is provided on the pressurizers. Overpressure protection consists of three spring-loaded ASME Code safety valves and two power-operated relief valves (PORVs) on each pressurizer.

The component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities for the pressurizers are listed in Table 3.1-1 of the LRA. The component/commodity groups which were identified in the table include shells, upper and lower heads, spray nozzles, surge nozzles, relief and safety valve nozzles, instrument nozzles, heater sleeves, surge nozzle safe ends, spray nozzle safe ends, relief nozzle safe ends, instrument nozzle safe ends, safety valve flanges, manway covers and bolting, heater sheaths, thermowells, support skirt integral attachments, and support skirt and flanges. The intended functions identified were pressure boundary and structural support.

2.3.1.2.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the pressurizers, and associated components and supporting structures, within the scope of license renewal, and subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the pressurizers and associated components, and compared the information in the UFSARs with the information in the LRA to identify those SCs that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

After completing the initial review, the staff requested the applicant to provide additional information on the pressurizer. The applicant's response to the RAIs, as submitted to NRC by letter dated October 3, 2002, are discussed below.

The UFSARs indicate that Units 1 and 2 are required to be in cold shutdown following some postulated fire events. However, the applicant states on page 3.1-11 of the LRA that the pressurizer spray heads do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and, therefore, are not within the scope of license renewal. In RAI 2.3.1-1, the staff asked the applicant to explain whether the components, which spray water inside the pressurizer to condense steam (auxiliary spray), are relied upon to take the units to cold shutdown following the postulated fire events, and to consider postulated SBO events that require the units to be in cold shutdown.

In Section 15.2.13 of the Unit 1 UFSAR and Section 15.10 of the Unit 2 UFSAR, the applicant stated that the CLB does not rely on pressurizer spray for SBO events. However, both UFSARs credit the use of auxiliary spray for RCS pressure control in support of achieving cold shutdown following postulated fire events. Auxiliary spray is provided from the chemical and volume control system via solenoid-operated auxiliary spray valves (see License Renewal Boundary Drawings 1-CVCS-02 and 2-CVCS-04). If the auxiliary spray valves are not available, the pressurizer PORVs are credited as an alternate means for RCS pressure control.

Since the auxiliary spray function is credited for plant shutdown during certain fire events, the pressurizer components that perform this function (spray nozzles and spray nozzle safe ends) are included in the scope of license renewal as identified in LRA Table 3.1-1 (pages 3.1-46 through 3.1-49). The license renewal intended function for these components is pressure boundary. However, the spray heads, which are attached to the spray nozzles inside the pressurizers, do not perform a pressure boundary function. The function of the pressurizer spray heads is to enhance the efficiency (i.e., RCS pressure control response time) of pressurizer spray during plant transients by atomizing the spray flow, thereby directly condensing the steam bubble.

Since the Fire Protection 10 CFR Part 50 Appendix R criteria allow up to 72 hours to achieve cold shutdown, this function is not required. It should be recognized that normal pressurizer spray flow is 375 gallons per minute (gpm), whereas auxiliary spray flow with one charging pump is only 44 gpm. Therefore, the effectiveness of the spray head is diminished during its use in auxiliary spray. Failure of the spray head would not prohibit the 120 °F spray water from entering the pressurizer and cooling the bulk pressurizer liquid volume. As previously mentioned, the flow rate of auxiliary spray utilizing one charging pump is 44 gpm. Assuming the normal liquid level of the pressurizer, the entire pressurizer liquid volume (approximately 6000 gallons) could be replaced in less than 3 hours during a plant cooldown. During a 72-hour period, this volume could be replaced multiple times, if required. This injection of cold water into the pressurizer, in combination with securing the normally energized proportional heaters, will result in significant cooling of the lower pressurizer shell. As a result, the lower pressurizer shell will act as a heat sink and cool the upper portion of the shell by direct conduction, in addition to its heat losses to the containment environment. Condensation of the steam bubbles will occur by heat transfer to the internal walls of the pressurizer and to the liquid surface at the vapor/water interface. Although some temperature stratification of the liquid volume may occur near the surface (i.e., vapor/water interface) as the steam condenses, the introduction of cold water into the top of the pressurizer will provide for mixing as the bulk fluid is drawn out of the bottom of the pressurizer through the surge line. The pressurizer heat losses to ambient during normal power operation are compensated for by the proportional heaters which have a rated capacity of 300 kilowatts (kW). Approximately 50 kW of this capacity is required to make up for ambient heat losses. In 1 hour, these heaters supply approximately 170,000 BTUs of heat energy to maintain pressurizer temperature/pressure. Based on the latent heat of vaporization, the amount of heat energy required (to be removed) to condense the entire 700 cubic foot (cu ft) volume of steam at 653 °F and 2225 pounds per square inch (psi) is approximately 1.8 million BTUs. This further supports the conclusion that 72 hours provides ample time to reduce pressurizer pressure.

The applicant further stated that although auxiliary spray is credited for achieving plant shutdown during certain fire events, there is an alternative method of achieving cold shutdown without the use of auxiliary spray or PORVs, as described in the Unit 2 UFSAR, Section 9.3.4.3.1.3.4 (page 9.3-32).

The applicant concludes that the pressurizer auxiliary spray heads at St. Lucie Units 1 and 2 are not relied on to demonstrate compliance with certain postulated fire events, as discussed in the above paragraphs; therefore, the spray heads are not within the scope of license renewal. The staff finds the applicant's assessment acceptable.

In Section 3.1.2 of the LRA, the applicant stated 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 stated 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. In Section 4.3.1 of the LRA, the applicant identifies fatigue as an aging effect requiring a time-limited aging analysis (TLAA). The staff concludes that since the thermal sleeves were credited in the TLAA for the nozzles (pressure boundary), the nozzles 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 stated 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 AMR. In RAI 2.3.1-2, the staff requested that the applicant perform an AMR of the subject components or justify why one is not required.

The applicant responded in a letter dated October 3, 2002, that 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 nozzle's 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 TLAA and dispositioned in LRA Subsection 4.3.1. 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 AMR.

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 Section 4.3.1. Accordingly, there are no aging effects requiring management for the thermal sleeves.

The applicant further stated that this conclusion is consistent with that included in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." 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 of the LRA was revised accordingly, 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.

The acceptability of the AMR results for the thermal sleeves is discussed in Section 3.1.2.2 of this SER. On the basis of the staff's review of the information presented in Section 2.3.1.2 of the LRA, the supporting information in the UFSARs, and the applicant's response to the RAIs, the staff did not identify any additional omissions by the applicant.

2.3.1.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the pressurizer components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessels

2.3.1.3.1 Summary of Technical Information in the Application

In Section 5.4 of the Unit 1 UFSAR and Section 5.3 of the Unit 2 UFSAR, the applicant describes the reactor vessels. The reactor vessels consist of cylindrical shells with hemispherical bottom heads and flanged removable upper heads. The component intended functions of the reactor vessels include pressure boundary integrity, reactor vessel internals structural support, reactor vessel structural support, refueling cavity structural support, and flow distribution.

The reactor vessel shells are fabricated from courses of multiple plates joined by axial and circumferential welds. The reactor vessels contain the cores, core support structures, control element assemblies, and other parts directly associated with the cores. Inlet and outlet nozzles are located at an elevation between the head flanges and the cores. Each removable reactor vessel upper head contains a bolting flange employing studs and nuts. Two metallic O-rings form a pressure tight seal in concentric grooves in the head flange. The O-rings are currently replaced each time the reactor vessel upper head is removed. Therefore, the O-rings are not long-lived and do not require an AMR, in accordance with 10 CFR 54.21(a)(1)(ii).

The control element drive mechanisms are attached to penetrations on the reactor vessel upper heads. In-core flux measuring instruments and heated junction thermocouples enter the upper heads through the in-core instrumentation flanges. The heated junction thermocouples on Unit 1 enter the upper head through two spare part length control element drive mechanism penetrations, instead of through the in-core instrumentation flanges. It should be noted that only the pressure boundary portions of the control element drive mechanisms are included in the scope of license renewal. The active portions of the control element drive mechanisms do not require an AMR in accordance with 10 CFR 54.21(a)(1)(i).

In Table 3.1-1 of the LRA, the applicant lists the component/commodity groups, and their intended functions, material, environment, and aging effects requiring management and programs/activities for the reactor vessels. The component/commodity groups which were identified in the table include closure head domes and flanges; closure studs; nuts; washers; control element drive mechanism nozzle tubes and flanges; control element drive mechanism motor housing/upper pressure housings and lower end fittings; primary inlet and outlet nozzles; primary inlet and outlet nozzle safe ends; nozzle support pads; upper, intermediate, and lower shells; vessel flanges, bottom heads; vent pipes; core stabilizing lugs; core stop lugs; in-core instrumentation nozzle tubes and flange adaptors/upper flanges/seal carrier assemblies; flow baffles; and refueling seal rings. The intended functions identified were pressure boundary, support of reactor vessel internals, flow distribution, reactor vessel support, and structural support to refueling cavity.

2.3.1.3.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the applicant has identified the reactor vessels and associated components and supporting structures, within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of its evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the reactor vessels and associated components and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

After completing the initial review, the staff requested the applicant to give additional information on the reactor vessels. The applicant's response to the requests for RAIs, as submitted to the NRC by letter dated October 3, 2002, is discussed below.

In Section 3.1.3 of the LRA, the applicant stated that reactor vessel flange leak detection lines do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and, therefore, are not within the scope of license renewal. On the basis of the staff's experience with license renewal, the staff has generally concluded that the inner O-ring, the leakoff lines, and the outer O-ring all support the reactor vessel closure head flange pressure boundary. (See NRC letter dated October 27, 1999, to the Babcock and Wilcox Owners Group.) In general, the leakoff lines require an AMR. The staff requested the applicant to provide a site-specific technical justification as to why aging management is not required or perform an AMR of these components. In response, the applicant stated that each leak detection line includes a 3/16-inch diameter orifice in the closure head which would limit any potential RCS leakage to within charging pump capacity in the unlikely event of leakage past the inner O-ring. Since the leak detection lines are non safety-related, and their potential failure would not prevent satisfactory accomplishment of any safety-related functions, the leak detection lines do not perform or support any license renewal intended functions that meet the scoping criteria of 10 CFR 54.4(a) and thus an AMR is not required. The staff finds the applicant's assessment acceptable.

On the basis of its review of the information presented in Section 2.3.1.3 of the LRA, the supporting information in the UFSARs, and the applicant's response to the RAIs, the staff did not identify any omissions by the applicant.

2.3.1.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the reactor vessel components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.4 Reactor Vessel Internals

2.3.1.4.1 Summary of Technical Information in the Application

In Section 4.2.2 of the Unit 1 UFSAR and Section 3.9.5 of the Unit 2 UFSAR, the applicant described the reactor vessel. The reactor vessel internals are designed to support, align, and guide the core components and to support and guide in-core instrumentation. The component intended functions of the reactor vessel internals include core support, flow distribution, I&C element assembly guidance and support, and vessel shielding.

The components of the reactor vessel internals subject to license renewal AMR can be divided into the following six groups for each unit:

(1) The upper internals assembly resides in the upper section of the core support barrel and is removed as one component during refueling. The functions of this assembly are to align and laterally support the upper end of the fuel assemblies, maintain the control element assembly spacing, hold down the fuel assemblies during operation, prevent fuel assemblies from being lifted out of position during severe accident conditions, protect the control element assemblies from the effect of coolant cross-flow in the upper plenum, and support the in-core instrumentation plate assembly.

(2) The control element shroud assembly is an integral part of the upper internals assembly. The shrouds extend vertically to provide support, alignment, and spacing for the control element assemblies and in-core instrumentation guide tubes.

(3) The core support barrel assembly consists of the core support barrel and its upper and lower flanges, the lower internals, and the core shroud. The core support barrel and the lower internals components welded to it are the container and support members for the reactor core. The Unit 1 core support barrel originally had a thermal shield; however, the degraded thermal shield was removed in 1983 without replacement. The related plant-specific reactor vessel internals operating experience is discussed in Subsection 3.1.4.3.2 of the LRA. The Unit 2 reactor vessel internals design does not include a thermal shield.

(4) The core shroud assembly is located within the core support barrel and below the upper internals assembly. The core shroud assembly is aligned by radial lugs and is attached to the core support plate. The core shroud assembly provides a boundary for the coolant flow and limits the amount of coolant bypass flow. The core shroud assembly also reduces the lateral motion of the fuel assemblies.

(5) The lower internals assembly is a welded structure consisting of a core support plate with fuel alignment pins, a cylinder, support columns, support beams, and a bottom plate. The lower internals assembly positions and provides axial support for the core. The cylinder guides the main coolant flow and limits the core shroud bypass flow.

(6) The in-core instrumentation plate assembly supports the instrument guide tubes and in-core thimbles. The in-core instrumentation plate assembly is designed to provide a passageway and guidance for each instrument, as well as provide protection from reactor coolant cross-flow.

In Table 3.1-1 of the LRA, the applicant lists the component/commodity groups within the scope of license renewal requiring an AMR and their intended functions, material, environment, and aging effects requiring management and programs/activities. The component/commodity groups identified in the table include the upper guide structure support plate, fuel alignment plate, guide lugs and inserts, hold down ring, control element assembly extension shaft guides, flow bypass inserts, control element assembly instrument tubes, dual tube control element assembly shrouds, control element assembly shroud base, in-core instrumentation support plate and guide tubes, single tube control element assembly shrouds, core support barrel, patches and expandable plugs, core shroud assemblies, core support plate, cylinder and bottom plate, core support barrel upper flange and alignment keys, fuel alignment pins, snubber spacer block, lower support structure beam assemblies, core support columns, control element assembly shroud bolts, fuel alignment plate guide lug bolts and insert bolts, core shroud tie-rods, and snubber bolts. The intended functions identified were core support, flow distribution, guide/support instrumentation and control element assemblies, and shield vessel.

2.3.1.4.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the reactor vessel internals, and associated components and supporting structures, within the scope of license renewal, and subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the reactor vessel internals and associated components and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

On the basis of its review of the information presented in Section 2.3.1.4 of the LRA, the supporting information in the UFSARs, and the applicant's response to the RAIs, the staff did not identify any omissions by the applicant.

2.3.1.4.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the reactor vessel internal components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.5 Reactor Coolant Pumps

2.3.1.5.1 Summary of Technical Information in the Application

In Section 5.5.5 of the Unit 1 UFSAR and Section 5.4.1 of the Unit 2 UFSAR, the applicant described the RCPs. Each reactor coolant loop contains two vertically mounted, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The RCPs provide the motive force for circulating the reactor coolant through the reactor core, primary loop piping, and steam generators. The component intended function of the RCPs is pressure boundary integrity.

The RCPs were manufactured by Byron Jackson. Associated components for the Class 1 RCPs include the pump case, pump cover, and closure bolting. The pump cover assembly includes the lower seal heat exchanger that cools the seal cartridge and thermal barrier, the radial bearing stator, and the upper and lower impeller labyrinth seals.

The seal cartridge consists of four face-type mechanical seals (three full-pressure seals mounted in tandem and a fourth low-pressure vapor seal designed to withstand system operating pressure when the pumps are not operating). A controlled bleed-off flow through the seals is used to cool the seals and to equalize the pressure drop across each seal. The RCP seals are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(ii) for the following reasons:

- Seal leakoff is closely monitored in the control room, and a high leakoff flow is alarmed as an abnormal condition requiring corrective action.

- The RCP seal package and its constituent parts are routinely inspected and parts replaced, as required based on condition, for each RCP.

- Plant operating experience has demonstrated the effectiveness of these activities.

Non-Class 1 piping, instrumentation, and other components attached to the RCPs are addressed in Subsection 2.3.1.1.2 of the LRA. Class 1 reactor coolant piping connected to the pumps, including the welded joints, is discussed in Subsection 2.3.1.1.1 of the LRA. The portions of the RCP rotating elements above the pump coupling, including the electric motor and the flywheel, are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i).

The component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities for the RCPs are listed in Table 3.1-1 of the LRA. The component/commodity groups which were identified in the table include casings and covers, lower seal heat exchanger tubes, and bolting. The intended function identified was pressure boundary.

2.3.1.5.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the RCPs and associated components and supporting structures within the scope of license renewal, and subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the RCPs and associated components and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA, to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

On the basis of the staff's review of the information presented in Section 2.3.1.5 of the LRA and the supporting information in the UFSARs, the staff did not identify any omissions by the applicant.

2.3.1.5.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the RCP components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.6 Steam Generators

2.3.1.6.1 Summary of Technical Information in the Application

In Section 5.5.1 of the Unit 1 UFSAR and Section 5.4.2 of the Unit 2 UFSAR, the applicant describes the steam generators. There are two steam generators installed in each unit, one in each reactor coolant loop. The component intended functions of the steam generators include pressure boundary integrity, heat transfer, flow distribution, structural support, and throttling.

The Unit 1 steam generators were replaced in December 1997 with Babcock and Wilcox International replacement steam generators of the same form, fit, and function. Although similar in general design concept and capacity, the Unit 1 replacement steam generators utilize materials that have improved resistance to known corrosion issues affecting pressurized-water reactor steam generators. The original Unit 2 steam generators remain in service.

Each steam generator is a vertical shell and tube heat exchanger, where heat transferred from a single-phase fluid at high temperature and pressure (the reactor coolant) on the tube side is used to generate a two-phase (steam-water) mixture at a lower temperature and pressure on the secondary side. The reactor coolant coming from the reactor vessel enters the steam generator through a single nozzle into the primary channel head, flows through the inverted U-tubes, and exits through two nozzles in the primary channel head to the RCPs. The head is divided into inlet and outlet chambers by a vertical divider plate. The steam-water mixture, generated in the secondary side, flows upward through the moisture separators to the steam outlet nozzle at the top of the vessel, providing essentially dry and saturated steam.

Manways are provided to permit access to both sides of the steam generator primary heads and to the moisture-separating equipment on the secondary side of the steam generators. The secondary side of the steam generators also contains the secondary side tube supports, tube bundle wrapper, Feedwater nozzle and distribution system, and moisture separation system.

The component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities for the steam generators are listed in Table 3.1-1 of the LRA. The component/commodity groups identified in the table include primary heads, stay cylinders, primary manway covers, primary inlet and outlet nozzles, primary inlet and outlet nozzle safe ends, tubesheets, primary instrument nozzles, U-tubes, tube plugs, divider plates, upper and lower shells, transition cones, secondary heads, Feedwater nozzles and safe ends, steam outlet nozzle safe ends, Unit 2 steam outlet nozzles, Unit 1 steam outlet nozzles with integral flow orifices, blowdown nozzles, secondary instrument nozzles, secondary manway and handhole closure covers, tube bundle wrappers and wrapper supports, tube support lattice bars, conical skirts, upper vessel clevises, and shear keys and boltings. The intended functions identified were pressure boundary, heat transfer, flow distribution, throttling, and structural support.

2.3.1.6.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the steam generators and associated components and supporting structures, within the scope of license renewal and subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the steam generators and associated components, and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

On the basis of the staff's review of the information presented in Section 2.3.1.6 of the LRA, and the supporting information in the UFSARs, the staff did not identify any omissions by the applicant.

2.3.1.6.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the steam generator components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features Systems

The Engineered Safety Features (ESF) systems consist of SCs designed to function under accident conditions to minimize the severity of an accident or to mitigate the consequences of an accident. In the event of a loss-of-coolant accident (LOCA), the ESF systems provide emergency coolant to assure the structural integrity of the core, to maintain the integrity of the containment, and to reduce the concentration of fission products expelled to the containment building atmosphere. Unless noted otherwise, the ESF systems for St. Lucie Units 1 and 2 are the same.

2.3.2.1 Containment Cooling

2.3.2.1.1 Summary of Technical Information in the Application

In Section 2.3.2.1 of the LRA, the applicant identifies the components of the containment cooling system that are within the scope of license renewal and subject to an aging management review. This system is further described in Section 6.2.2.2.2 of the UFSARs for both St. Lucie Units 1 and 2. The containment cooling system provides the intended function of maintaining the containment below its structural design pressure and temperature limits following a design-basis event (DBE) by removing heat. The system is designed to operate after a DBE to remove heat and reduce the pressure in containment to atmospheric. Heat removed from the containment is transferred to component cooling water. The component cooling water system is discussed in Section 2.3.3.2 of the LRA.

The containment cooling system consists of four fan cooler units, a ducted air distribution system, and associated instrumentation and controls. The four units are located outside the secondary shield wall in four different quadrants of each containment. Each fan cooler consists of two banks of cooling coils, a housing, a fan, and a motor. Each cooling coil bank is made up of coil sections connected to supply and return manifolds of the component cooling water system. In Unit 1, a centrifugal fan is employed in each fan cooler. Fan motors are totally enclosed fan-cooled type with an integrally mounted air-to-water heat exchanger to form an entirely closed cooling system. Cooling water comes from the component cooling water system. Each fan cooler in Unit 2 employs an axial flow fan with a totally enclosed air-over type motor.

In both St. Lucie units, the discharge side of the fan coolers are connected through duct risers to the ring header manifold. An adequate quantity of air outlets is provided around the periphery of the ring header to promote mixing and good distribution of air. Blowout panels are provided on the duct risers to attenuate any high-pressure transmission from inside the secondary shield wall area through the duct. During normal conditions, any three of the four fan coolers are in operation. Each unit is sized to remove one-third of the total normal heat load or one-fourth of the accident load. The fourth fan cooler is automatically started upon receipt of a safety injection actuation signal.

The containment cooling system is in the scope of license renewal because it contains SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are a part of the EQ Program, and SCs that are relied upon during certain fire events.

On the basis of the intended functions previously identified, the applicant compiled a list of component types that are within the scope of license renewal and subject to an AMR. The list provided in Table 3.2-1 includes valves (Unit 1 only), piping/fittings, flexible connections, drip pans and thermowells, ducts, and bolting (mechanical closures). In addition, the components of the containment fan coolers subject to an AMR include fan housings, heat exchanger tubes, fins, headers, and end caps; vent plugs and frame side plates; heat exchanger stubs/flanges; motor heat exchanger tubes, fins, and headers (Unit 1 only); and closed cooling water flanges (Unit 2 only). The list of components subject to an AMR is specific for each unit because of design differences. That is, Unit 1 has a centrifugal fan in each fan cooler, while Unit 2 employs an axial flow fan with a totally enclosed air-over type motor.

Table 3.2-1 of the LRA lists pressure boundary as the intended function for the components of the containment cooling system that are subject to an AMR, with the exception of the containment fan motor heat exchanger fins. Heat transfer is listed as the intended function for the containment fan motor heat exchanger fins and as an additional intended function for the containment fan cooler heat exchanger tubes and containment fan cooler motor heat exchanger tubes.

2.3.2.1.2 Staff Evaluation

The staff reviewed Section 2.3.2.1 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment cooling system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.2-1 of the LRA to determine whether the applicant adequately identified the components of the containment cooling system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the containment cooling system that were not listed in Table 3.2-1 of the LRA to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 6.2.2.2.2 of the UFSARs for Units 1 and 2 and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.2.1 of the LRA.

During the review, the staff questioned the applicant's omission from the scope of license renewal of certain passive and long-lived components of the containment cooling system which are described in the UFSAR, such as the duct risers and ring header. These components are not specifically listed in Table 3.2-1 of the LRA or shown as being within the scope of license renewal in the license renewal boundary drawings 1-HVAC-01 and 2-HVAC-02 for Units 1 and 2, respectively. In relation to the previously noted components, these HVAC drawings do not show the containment cooling system in sufficient detail to determine the system boundaries for license renewal. As an example, the notation "to ring header" shown on the downstream side of the fan coolers does not indicate exactly which components are designated as being within the scope of license renewal. By letter dated July 1, 2002, the staff requested that the applicant identify components of the containment cooling system that are within scope and subject to an AMR by providing additional text description, drawings, and/or references to supplement Section 2.3.2.1 of the LRA (RAI 2.3.2-2).

The applicant responded to this RAI by letter dated October 3, 2002, and stated that duct risers and ring headers are components that perform system intended functions and are therefore within the scope of license renewal and subject to an AMR. Although duct risers and ring headers were not listed in Table 3.2-1 of the LRA, they have been included in the component grouping "ducts."

However, the applicant's response to RAI 2.3.2-2 did not include the requested information or drawings to facilitate the staff's review of the containment cooling system. Therefore, the staff reexamined the UFSARs, the original licensing SERs and supplements, and the IPE and IPEEE reports to determine whether components of the containment cooling system that perform an intended function as defined in 10 CFR 54.4(a) are in the scope of license renewal and subject to an AMR. On page 6.2-36 of the Unit 2 UFSAR, the applicant states that "blowout panels are provided on the duct risers between the fan coolers and ring header to attenuate high-pressure transmission from inside the secondary shield wall through the duct." On page 6.2-50 of the Unit 2 UFSAR, similar blowout panels are described as components of the containment cooling system. These components are passive and long-lived and perform an intended function. However, Table 3.2-1 of the LRA did not explicitly include blowout panels as components within the scope of license renewal and subject to an AMR. The staff therefore issued a followup RAI by letter dated July 18, 2002, that requested the applicant to justify the exclusion of blowout panels from Table 3.2-1 (RAI 2.3.2-4).

The applicant responded to RAI 2.3.2-4 by letter dated October 3, 2002. In its response, the applicant stated that blowout panels are components that perform system intended functions and are therefore within the scope of license renewal and subject to an AMR. Although blowout panels were not listed in Table 3.2-1 of the LRA, they are included in the component grouping "ducts."

Similarly, Figure 6.2-46 of the UFSAR for Unit 1 shows drum-type air outlets at numerous locations in the containment cooling system. However, these outlets were not identified in Table 3.2-1 of the LRA nor shown on license renewal boundary drawing 1-HVAC-01. These components are also passive and long-lived and perform an intended function. By letter dated July 18, 2002, the staff requested that the applicant justify why the air outlet components are not listed in Table 3.2-1 as being within the scope of license renewal and subject to an AMR (RAI 2.3.2-5).

The applicant responded to this RAI by letter dated October 3, 2002, and stated that the drum-type air outlets are within the scope of license renewal and subject to an AMR. Although the drum-type air outlets were not explicitly listed in Table 3.2-1 of the LRA, they are included in the component grouping "ducts".

Dampers are shown at numerous locations in the containment cooling system in Figure 6.2-46 of the UFSARs for Units 1 and 2. The housings for these components were neither identified in Table 3.2-1 of the LRA nor shown on license renewal boundary drawings 1-HVAC-01 and 2-HVAC-01. Since these dampers perform an intended function in limiting differential pressure in the ring header and duct risers, and the damper housings are passive and long-lived, the staff considered these housings to be within the scope of license renewal and subject to an AMR. By letter dated July 18, 2002, the staff requested that the applicant justify why the damper housings were not subject to an AMR (RAI 2.3.2-6).

The applicant responded to this RAI by letter dated October 3, 2002. In its response, the applicant stated that dampers were not listed in Table 3.2-1 of the LRA because they were considered to be active components and thus not subject to an AMR, in accordance with 10CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. However, on the basis of the staff's position on previous LRA and expectations expressed by the staff at meetings, the applicant has revised Table 3.2-1 to include damper housings.

The staff considers the applicant's responses to RAIs 2.3.2-2, 2.3.2-4, 2.3.2-5, and 2.3.2-6 acceptable, on the basis that (1) the applicant has clarified that the components referred to by the RAIs are included in component groupings already listed in Table 3.2-1 of the LRA, and (2) the applicant has included a revised version of Table 3.2-1 that includes damper housings as within the scope of license renewal and subject to an AMR in accordance with the requirements of 10CFR 54.4(a) and 10CFR 54.21(a)(1), respectively.

The staff's review found that the components of the containment cooling system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the containment cooling system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.2 Containment Spray

2.3.2.2.1 Summary of Technical Information in the Application

In Section 2.3.2.2 of the LRA, the applicant identifies the components of the containment spray system that are within the scope of license renewal and subject to an AMR. This system is further described in Section 6.2.2.2.1 of the UFSARs for both St. Lucie Units 1 and 2.

The containment spray is an ESF with the intended functions of removing sufficient heat to maintain the containment pressure and temperature below their design limits following DBEs and removing fission product iodine from the post-accident containment atmosphere. The containment spray system for each unit consists of two containment spray pumps that take suction from the refueling water tanks and spray borated water from nozzles located near the top of each containment structure. When refueling water tank inventory is exhausted, containment spray pump suction is switched to the containment recirculation sumps, and the shutdown cooling heat exchangers are used to remove heat from the recirculated water. The shutdown cooling heat exchangers are scoped and screened with the safety injection system in Section 2.3.2.4.

Chemicals are injected into the containment spray pump suction lines during containment spray operations to control pH and for iodine absorption. Unit 1 has a sodium hydroxide tank that supplies sodium hydroxide through eductors to the suction lines of the containment spray pumps. Unit 2 has hydrazine pumps that inject hydrazine from a hydrazine storage tank into the suction lines of the containment spray pumps. In addition, Unit 2 utilizes solid trisodium phosphate dodecahydrate (TSP) in stainless steel mesh baskets located in the vicinity of the containment recirculation sumps to control post-accident pH. The stainless steel mesh baskets are scoped and screened with civil/structural components in Section 2.4.1.1.

The containment spray system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs, SCs that are a part of the EQ Program, SCs that are relied upon during certain fire events, and SCs that are relied upon during SBO events (Unit 2 only).

On the basis of the intended functions of the containment spray system, the applicant listed the containment spray system component types subject to an AMR in Table 3.2-2 of the LRA. They consist of refueling water tanks, sodium hydroxide tank (Unit 1 only), hydrazine tank (Unit 2 only), pumps and valves (pressure boundary only), heat exchangers, eductors, orifices, strainers, thermowells, spray nozzles, vortex breaker (Unit 1 only), rupture discs (Unit 1 only), sight-glasses (Unit 1 only), piping, tubing, fittings, and bolting. The list of components subject to an AMR is specific for each unit because of design differences. That is, Unit 1 has a sodium hydroxide tank, while Unit 2 has hydrazine pumps and a hydrazine storage tank.

In Table 3.2-2 of the LRA, the applicant further identified the intended functions for containment spray components subject to an AMR as pressure boundary, heat transfer, vortex prevention, spray, throttling, and filtration.

2.3.2.2.2 Staff Evaluation

The staff reviewed Section 2.3.2.2 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment spray system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.2-2 of the LRA to determine whether the applicant appropriately identified the components of the containment spray system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the containment spray system that were not listed in Table 3.2-2 to verify, with reasonable assurance, that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 6.2.2.2.1 of the St. Lucie UFSARs for Units 1 and 2 and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.2.2 of the LRA.

During the review, the staff asked the applicant to clarify terminology used in Table 3.2-2 of the LRA. Specifically, the staff asked whether the "NaOH Tank rupture disc (Unit 1 only)" component listed in the internal environment section of Table 3.2-2 on page 3.2-14 is the same as the "rupture disc" component listed in the external environment section of that table on page 3.2-19. In a meeting on May 15 and 16, 2002 (documented in a summary dated June 21, 2002), the applicant confirmed that these terms referred to different sides of the same component, and that this component was considered to be within the scope of license renewal and subject to an AMR. The staff finds the applicant's response acceptable because it clarifies the identification of this component consistent with the general information and descriptions provided in Section 2.3.2.2 of the LRA and the UFSARs for both units concerning the containment spray system.

The staff's review found that the components of the containment spray system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the containment spray system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.3 Containment Isolation

2.3.2.3.1 Summary of Technical Information in the Application

In Section 2.3.2.3 of the LRA, the applicant identifies the components of the containment isolation system that are within the scope of license renewal and subject to an AMR. The containment isolation system is further described in Section 6.2.4 of the UFSARs for both St. Lucie Units 1 and 2.

The containment isolation system is an ESF with the intended function of providing for the closure or integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment. Not all fluid-bearing lines penetrating the containment are scoped as part of the containment isolation system. Process systems that have system intended functions in addition to the containment isolation function are included in the screening and scoping results described in Section 2.3. In addition, the pressure boundary (metallic) portions of electrical penetrations and miscellaneous/spare mechanical penetrations that are not associated with a process system are included in the civil/structural screening and scoping results described in Section 2.4. The nonmetallic and conductor portions of containment electrical penetrations are included in the electrical/I&C scoping and screening results described in Section 2.5. The applicant has stated that all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described, are subject to an AMR.

The containment isolation system comprises those portions of the containment purge, hydrogen purge (Unit 1), continuous containment/hydrogen purge (Unit 2), integrated leak rate test, service air, and containment vacuum relief that have a containment pressure boundary intended function.

Containment vacuum relief has the additional intended function of protecting the containment vessels from subatmospheric internal pressure conditions created by a containment overcooling event. This system has pneumatically operated butterfly valves installed on the shield building annulus side of the containment penetration that serve as automatic vacuum relief valves as well as containment isolation valves. A separate pressure controller that senses the differential pressure between the containment and the annulus actuates each butterfly valve. Each butterfly valve is provided with an air accumulator enabling the valve to open following a loss of instrument air. However, the air accumulators have been scoped and screened with the components of the instrument air system in Section 2.3.3.8 of the LRA.

The containment purge system is in the scope of license renewal because it contains. SCs that are safety-related and are relied upon to remain functional during and following DBEs and SCs that are a part of the EQ Program (Unit 2 only).

The hydrogen purge system (for Unit 1), the continuous containment/hydrogen purge (for Unit 2), and service air systems are in the scope of license renewal because they contain SCs that are safety-related and are relied upon to remain functional during and following DBEs , SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the functions of safety-related SCs, and SCs that are a part of the EQ Program.

The integrated leak rate test system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs and SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the functions of safety-related SCs.

The containment vacuum relief system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs and SCs that are a part of the EQ Program.

On the basis of the intended functions of the containment isolation system, the applicant listed in Table 3.2-3 of the LRA the component types in this system that are within the scope of license renewal and subject to an AMR. These component types consist of valves (pressure boundary only), piping, tubing, fittings, debris screens, and bolting(mechanical closures). In Table 3.2-3, the applicant identified the intended functions of these component types to be pressure boundary and filtration.

2.3.2.3.2 Staff Evaluation

The staff reviewed Section 2.3.2.3 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment isolation system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.2-3 of the LRA to determine whether the applicant appropriately identified the components of the containment isolation system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the containment isolation system that were not listed in Table 3.2-3 of the LRA to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 6.2.4 of the UFSARs for both units and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.2.3 of the LRA.

The staff's review found that the components of the containment isolation system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the containment isolation system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.4 Safety Injection System

2.3.2.4.1 Summary of Technical Information in the Application

In Section 6.3 of the Unit 1 and 2 UFSARs, the applicant described the safety injection (SI) system. In Section 9.3.5 of the Unit 1 UFSAR and Section 5.4.7 of the Unit 2 UFSAR, the applicant described the shutdown cooling and safety injection components required to perform shutdown cooling functions. The SI system includes the safety injection tanks, which provides emergency core cooling and reactivity control during and following DBEs. Portions of the SI system are also used for shutdown cooling functions. In addition, some portions of the SI system, including the shutdown cooling heat exchangers, are used in conjunction with the containment spray system to cool the containment. The flow diagrams listed in Table 2.3-2 of the LRA show the evaluation boundaries for the portions of the SI system that are within the scope of license renewal.

The SI system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, SCs that are a part of the EQ Program, and SCs that are relied upon during certain postulated fire (Units 1 and 2) and SBO events (Unit 2 only).

The component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities are listed in Table 3.2-4 of the LRA. The component/commodity groups which were identified in the table include safety injection tanks, pumps and valves (pressure boundary only), heat exchangers, orifices, thermowells, piping, tubing, and fittings. The intended functions for SI components subject to an AMR include pressure boundary integrity, heat transfer, and throttling.

2.3.2.4.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the SI system components and supporting structures within the scope of license renewal and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the SI system and associated components and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSARs for any functions delineated under 10 CFR 54.4(a) that were not identified as intended functions in the LRA to verify that the SSCs with such functions will be adequately managed, so that the functions will be maintained consistent with the CLB for the extended period of operation.

After completing the initial review, the staff requested the applicant to give additional information on the SI system. The applicant's responses to the RAIs, as submitted to NRC by letter dated October 3, 2002, are discussed below.

During the injection mode for a small break LOCA, a portion of the high-pressure safety injection (HPSI) flow is returned to the refueling water tank (RWT) through the bypass line. A section of the bypass line (1-SI-02, location A7, and 2-SI-02, location B4) near the RWT is not safety related, and the LRA shows that it is not within the scope of license renewal. If this piping fails and flow is not returned to the RWT, the inventory of the tank could be prematurely exhausted. For both units, there are orifices in the bypass lines which restrict the maximum bypass flow. The Unit 1 bypass flow is 30 gpm per pump (per Table 6.3-2 of the Unit 1 UFSAR) for operation at rated HPSI flow. No specific bypass flow rate could be identified in the Unit 2 UFSAR. For breaks of sufficiently small size, the bypass flow can continue to leak out for a long period of time, potentially exhausting the supply of coolant from the RWT. The failure of the non safety-related piping in the bypass line could prevent satisfactory accomplishment of the safety-related intended function of the HPSI system. In RAI 2.3.2-1, the staff requested the applicant to justify why the piping and valve body components in the bypass piping to the RWT are not within the scope of license renewal and subject to an AMR.

In its response, the applicant explained that the non safety-related SI piping identified in RAI 2.3.2-1 is classified Quality Group D, consistent with the CLB. The function of these lines is to ensure that the minimum required flow for the HPSI pumps is provided during shutoff head conditions, such as periodic ASME Boiler and Pressure Vessel Code pump tests, to preclude hydraulic instability and pump overheating. The orifices installed in these lines limit flow to approximately 30 gpm per pump for both units. For RCS breaks of the size identified in RAI 2.3.2-1, emergency operating procedures require that the units be cooled down to the point that shutdown cooling can be initiated. Within a maximum of 10 hours of the event, shutdown cooling would be in service. Assuming failure of the HPSI pump recirculation line, a total RWT inventory of 18,000 gallons would be unavailable for use (30 gpm x 60 minutes x 10 hours). The minimum required technical specification levels for the Unit 1 and Unit 2 RWTs are 401,800 gallons and 417,100 gallons, respectively. Thus, RWT inventory is more than adequate for the scenario. The Unit 1 UFSAR, Section 6.3.2.2.4, and the Unit 2 UFSAR, Section 6.3.2.2.3, do not credit the recirculation path for anything other than pump minimum flow. Accordingly, this piping does not support or perform any license renewal intended functions that meet the scoping criteria of 10 CFR 54.4(a) and thus an AMR is not required. The staff finds the applicant's assessment, as discussed above, acceptable.

On the basis of the staff's review of the information presented in Section 2.3.2.4 of the LRA, the supporting information in the UFSARs, and the applicant's response to the RAIs, the staff did not identify any omissions by the applicant.

2.3.2.4.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the safety injection system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.5 Containment Post-Accident Monitoring

2.3.2.5.1 Summary of Technical Information in the Application

In Section 2.3.2.5 of the LRA, the applicant identifies the components of the containment post-accident monitoring system that are within the scope of license renewal and subject to an AMR. The containment post-accident monitoring system includes the containment hydrogen monitoring, post-accident sampling (Unit 2 only), and containment atmosphere radiation monitoring subsystems. Each subsystem is described in separate UFSAR sections. Containment hydrogen monitoring is described in Section 6.2.5.2.3 of the Unit 1 UFSAR, and Section 6.2.5.2.1 of the Unit 2 UFSAR; post-accident sampling is described in Section 9.3.6 of the Unit 2 UFSAR; and containment atmosphere radiation monitoring is described in Section 12.2.4.1 of the Unit 1 UFSAR and Section 12.3.4.2.3.1 of the Unit 2 UFSAR.

The applicant describes the containment post-accident monitoring system, which includes the containment hydrogen monitoring, post-accident sampling (Unit 2 only), and containment atmosphere radiation monitoring subsystems. The containment post-accident monitoring system is an ESF with the intended functions of (1) providing an indication of the hydrogen gas concentration in the containment atmosphere following a LOCA, and (2) measuring radioactivity in the containment air. The containment hydrogen monitoring system is used to monitor the level of hydrogen in containment following a LOCA. Components of this system are the sample and return tubing, associated valves, hydrogen analyzer, grab sample cylinder, sample pump, moisture separator, cooler, instruments, calibration gas line, reagent gas line, and nitrogen purge gas supply. The post-accident sampling system consists of a shielded skid-mounted sample station, a remotely located control panel, and a remote dissolved oxygen indicating panel. This system provides a means to obtain and analyze reactor coolant samples and containment building samples. The containment atmosphere radiation monitoring system provides a continuous indication in the control room of the particulate and gaseous radioactivity levels inside the containment.

The containment post-accident monitoring system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the functions of safety-related SCs, or SCs that are part of the EQ Program, or SCs that are relied on during certain fire events, and SBO events (Unit 2 only).

The applicant listed in Table 3.2-4 of the LRA the containment post-accident monitoring component types subject to an AMR. These include valves (pressure boundary only), sample vessel, flexible hoses, piping, tubing, and fittings. The applicant further identified the intended function for containment post-accident monitoring components subject to an AMR as pressure boundary.

2.3.2.5.2 Staff Evaluation

The staff reviewed Section 2.3.2.5 of the LRA and the associated license renewal boundary diagrams to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment post-accident monitoring system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.2-5 of the LRA to determine whether the applicant appropriately identified the components of the containment post-accident monitoring system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the containment post-accident monitoring system that were not listed in Table 3.2-5 to verify, with reasonable assurance, that the applicant properly identified the components that meet the above requirements. The staff also reviewed Sections 6.2.5.2.3 and 12.2.4.1 of the Unit 1 UFSAR and Sections 6.2.5.2.1, 9.3.6, and 2.3.4.2.3.1 of the Unit 2 UFSAR and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.2.5 of the LRA.

During the review, the staff observed that the containment post-accident monitoring system beyond the outboard containment isolation valves is not within the scope of license renewal (see license renewal boundary drawings 1-SAMP-02 and 2-SAMP-03 for Units 1 and 2, respectively). These piping runs lead to the containment atmosphere radiation monitors, which provide a continuous indication of particulate and gaseous radioactivity levels inside the containment. To confirm that the applicant correctly excluded these components, the staff reviewed Section 12.2.4.1 of the Unit 1 UFSAR and Section 12.3.4.2.3.1 of the Unit 2 UFSAR and determined that the containment atmosphere radiation monitors provide a continuous indication of particulate and gaseous radioactivity levels inside the containment, which is a non safety-related process monitoring function. Therefore, the staff concurred with the applicant's exclusion of the portion of the containment post-accident monitoring system beyond the containment isolation valves on the basis that these components do not perform an intended function that would place them within the scope of license renewal.

The staff's review found that the components of the containment post-accident monitoring system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.5.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the containment post-accident monitoring system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In Section 2.3.3, "Auxiliary Systems," of the LRA, the applicant describes the structures, systems, and components of the auxiliary systems that are subject to an AMR.

As described in the LRA, the auxiliary systems are those systems used to support normal and emergency plant operations. The systems provide cooling, ventilation, sampling, and other required functions. Unless noted otherwise, the auxiliary systems for St. Lucie Units 1 and 2 are the same.

2.3.3.1 Chemical and Volume Control System

2.3.3.1.1 Summary of Technical Information in the Application

In Section 9.3.4 of the Unit 1 and 2 UFSARs, the applicant described the chemical and volume control system (CVCS). The CVCS provides a continuous feed and bleed for the RCS to maintain proper water level and to adjust boron concentration. The CVCS consists of a charging subsystem, a letdown subsystem, and a boric acid makeup subsystem.

The flow diagrams listed in Table 2.3-3 of the LRA show the evaluation boundaries for the portions of the CVCS that are within the scope of license renewal. Insulation is not within the scope of license renewal for the CVCS because the system does not contain boric acid solutions at concentrations that require heat tracing, tank heaters, and/or insulation to prevent precipitation.

The CVCS is in the scope of license renewal because it contains SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, SCs that are part of the EQ Program, and SCs that are relied on during postulated fires and SBO events.

In Table 3.3-1 of the LRA, the applicant lists the component/commodity groups and their intended functions, material, environment, and aging effects requiring management and programs/activities. The component/commodity groups identified in the table include pumps and valves (pressure boundary only), housings, tanks, heat exchangers, strainers, orifices, thermowells, piping, tubing, and fittings. The intended functions for the CVCS components subject to an AMR include pressure boundary integrity, filtration, and throttling.

2.3.3.1.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the CVCS components and supporting structures within the scope of license renewal and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for the CVCS and associated components, and compared the information in the UFSARs with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a) and, for those SCs that have an applicable intended function(s), they either perform this function(s) with moving parts or a change in configuration or properties, or they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the SSCs with such function(s) will be adequately managed, so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

On the basis of the staff's review of the information presented in Section 2.3.3.1 of the LRA, the supporting information in the UFSARs, and the applicant's response to the RAIs, the staff did not identify any omissions by the applicant.

2.3.3.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the CVCS components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.2 Component Cooling Water

2.3.3.2.1 Technical Information in the Application

In Section 2.3.3.2 of the LRA, the applicant identifies the parts of the component cooling water system that are within the scope of license renewal and subject to an AMR. This system is further described in Section 9.2.2 of the Unit 1 and 2 UFSARs.

The component cooling water system is an auxiliary system whose intended function is to remove heat from safety-related and non-safety-related components during normal and emergency operation. In addition, the component cooling water system provides an intermediate radiological barrier between the reactor coolant and the intake cooling water systems and a heat sink for safety-related components associated with reactor decay heat removal for safe shutdown or LOCA conditions. The component cooling water pumps circulate component cooling water through heat exchangers and coolers that are associated with other systems to transfer heat from those systems to component cooling water. The component cooling water heat exchangers transfer heat from component cooling water to intake cooling water. The applicant considers the other coolers and heat exchangers cooled by the component cooling water system to be part of their respective systems and scoped and screened these coolers and heat exchangers associated with those systems.

The component cooling water system is in the scope of license renewal because it contains SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs, SCs that are part of the EQ Program, and SCs that are relied on during fire events.

In Table 3.3-2 of the LRA, the applicant listed the component types present in the component cooling water system that are subject to an AMR as pumps and valves (pressure boundary only), heat exchangers, tanks, orifices, thermowells, sight-glasses, piping, tubing, and fittings. The applicant later identified additional pipe/fittings and valves present in the component cooling water system as subject to an AMR in its September 26, 2002, response to RAI 2.1-1 (discussed in Section 2.1 of this SER). The applicant identified the intended functions of the component cooling water system components subject to an AMR as pressure boundary, heat transfer, and throttling.

2.3.3.2.2 Staff Evaluation

The staff reviewed Section 2.3.3.2 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the component cooling water system that are within the scope of license renewal, in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-2 of the LRA to determine whether the applicant appropriately identified the components belonging to the component cooling water system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the component cooling water system that were not listed in LRA Table 3.3-2 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 9.2.2 of the St. Lucie UFSARs for Units 1 and 2 and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.2 of the applicant's LRA.

As a result of this review, the staff identified the need for additional information. By letter dated July 18, 2002, the staff requested the applicant to justify why four temporary air chillers attached to the essential component cooling water loops, shown on St. Lucie Unit 1 Drawing 1-CCW-01, were not identified as being within the scope of license renewal. The staff added that these chillers were not described in the Unit 1 UFSAR (RAI 2.3.3-1).

In its response dated October 3, 2002, the applicant stated that the chillers attached to the component cooling water system are temporary, rented units utilized for air conditioning the containment for human comfort during refueling outages. The chillers supply chilled water to the containment fan coolers through "outage use only" chiller connections to the component cooling water piping and are not utilized during normal power operations. According to the St. Lucie technical specifications, containment fan cooler operability is required in Modes 1, 2, and 3. The chillers may be operated only in Modes 5 and 6, and before they are operated, the component cooling water header supply and return to the fan cooler units are isolated by closing MV-14-5, MV-14-6, MV-14-7, and MV-14-8, as shown on license renewal boundary drawing 1-CCW-01. Therefore, the integrity of the pressure boundary of the "in-use" safety-related portions of the component cooling water system would not be affected by any postulated failures of the temporary chillers. Containment isolation during Modes 5 or 6 is provided by manual valves SB14517, SB14518, SB14519, and SB14520 (shown on license renewal boundary drawing 1-CCW-01), as identified on Unit 1 UFSAR Table 6.2-16. Accordingly, the chiller connections are classified as non-nuclear-safety-related, and the temporary air conditioning chillers do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff finds the applicant's response acceptable on the basis that (1) the pressure boundary integrity of the "in-use" safety-related portions of the component cooling water system would not be affected by failures of the temporary chillers, and (2) the temporary air conditioning chillers do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff review found that the parts of the component cooling water system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the component cooling water system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Demineralized Makeup Water

2.3.3.3.1 Summary of Technical Information in the Application

In Section 2.3.3.3 of the LRA, the applicant identifies the components of the Unit 2 demineralized makeup water (DW) system that are within the scope of license renewal and subject to an AMR. The DW system is described in Section 9.2.3 of the Unit 2 UFSAR.

The Unit 1 DW system is not identified as within the scope of license renewal in the LRA as originally submitted. However, in the response, dated September 26, 2002, to the staff's RAI concerning non safety-related SCs whose failure could prevent satisfactory accomplishment of the function of safety-related SCs, the applicant included components of the Unit 1 DW system that are within the scope of license renewal and subject to an AMR. The Unit 1 DW system is described in Section 9.2.5 of the Unit 1 UFSAR.

As stated in the UFSARs, the DW systems for both Units 1 and 2 are non safety-related systems and serve no safety-related functions. No DW system line penetrates the containment. Water from the common site makeup demineralizer is provided to the makeup water systems for each unit, which supply demineralized water for makeup to a number of systems, including diesel generator cooling water makeup and turbine cooling water.

The DW systems are in the scope of license renewal because they contain structures or components whose failure could prevent satisfactory accomplishment of the intended function of safety-related structures or components. The LRA identifies components of the Unit 2 DW system which enter and are routed in the diesel generator building as being subject to an AMR. These components were designed to seismic Category I requirements to preclude their failure during a seismic event. In response to the staff's RAI 2.1-1, the applicant included additional components located in the Unit 2 reactor auxiliary building as being subject to an AMR.

None of the Unit 1 DW system piping and components was initially identified as subject to an AMR by the applicant in the LRA, because none of the Unit 1 DW system components is designed to seismic Category I requirements. However, in response to the staff's RAI 2.1-1, the applicant identified DW components located in the Unit 1 EDG buildings and the Unit 1 reactor auxiliary building whose failure could prevent satisfactory accomplishment of the intended function of a safety-related SC. The applicant included these components as additional components to be subject to an AMR.

In Table 3.3-3 of the LRA, the applicant identified valves, piping/fittings, and bolting (mechanical closures) as Unit 2 DW system component types subject to an AMR. As discussed above and in Section 2.1 of this SER, the applicant also identified the DW system pipe/fittings and valves located in the Unit 1 EDG buildings and the Unit 1 reactor auxiliary building as subject to an AMR in the response to the staff's RAI 2.1-1. The intended function for DW components subject to an AMR is pressure boundary.

2.3.3.3.2 Staff Evaluation

The staff reviewed Section 2.3.3.3 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the DW system that are within the scope of license renewal, in accordance with 10 CFR 54.4(a). The staff reviewed Table 3.3-3 of the LRA to determine whether the applicant appropriately identified the components of the DW system that are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the DW system that were not listed in Table 3.3-3 to verify that the applicant appropriately identified the components that meet the above requirements. The staff also reviewed Sections 9.2.5 and 9.2.3 of the UFSARs for Units 1 and 2, respectively, and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.3 of the LRA.

In a meeting with the staff on June 10 and 11, 2002, the applicant clarified the intended support function of the DW system that led to its determination that a portion of the Unit 2 piping for this system is in the scope of license renewal. Also, the applicant confirmed that the Unit 1 DW system piping does not perform an intended function of pressure boundary; however, the components of the Unit 1 DW system were being brought within the scope of license renewal in response to the staff's RAI 2.1-1. In the response to the staff's RAI 2.1-1, the applicant states, in part, that it evaluated the potential for non safety-related structures or components having a spatial interaction with safety-related structures and components in each of the Unit 1 and 2 structures and areas that contained piping and components of the DW system. Consequently, the applicant bought into scope additional Unit 2 DW components in the Unit 2 reactor auxiliary building and Unit 1 DW components in the Unit 1 diesel generator building and the Unit 1 reactor auxiliary building.

The staff finds the applicant's response to the portion of RAI 2.1-1 that relates to the DW system to be acceptable on the basis that (1) it clarifies the basis for the DW system to be considered within the scope of license renewal because the DW system contains non safety-related structures or components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components, and (2) it identifies the components which are subject to an AMR for both units.

The staff's review found that the components of the DW system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the DW system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Diesel Generators and Support Systems

2.3.3.4.1 Summary of Technical Information in the Application

In Section 2.3.3.4 of the LRA, the applicant identifies the components of the EDGs and support systems that are within the scope of license renewal and subject to an AMR. These systems are further described in Sections 8.3 and 9.5 of the UFSARs for both St. Lucie Units 1 and 2.

The EDGs provide Alternating current (AC) power to the onsite electrical distribution system to assure the capability for a safe and orderly shutdown. The EDG support systems listed below are necessary to ensure proper operation of the EDGs.

- air intake and exhaust
- air start
- fuel oil
- lube oil
- cooling water

Four EDGs supply independent standby AC power to Units 1 and 2. Each EDG set consists of two diesel engines mounted in tandem with a 3500 kW generator at Unit 1 and a 3800 kW generator at Unit 2 and auxiliary systems (air starting, fuel supply, cooling water, and lubricating oil).

In an SBO event where all offsite and onsite power sources fail except for one EDG from Unit 2, power is transferred from the only operating EDG from Unit 2 to one of the Unit 1 4.16-kV Class 1E distribution busses via the SBO cross-tie. This SBO cross-tie connects the two safety-related swing 4.16-kV busses, 1AB and 2AB.

With the exception of the Unit 1 diesel oil storage tanks, other components of the emergency portion of the auxiliary power system which are essential to shutdown and to maintain the units in a safe condition are housed within structures that are designed to withstand design-basis tornado wind loadings, missiles, and maximum flood levels.

Air Intake and Exhaust. The EDGs use intake air from the surrounding ambient air in the EDG building. Intake air entering the EDG building between Elevation 19 feet and 22.9 feet is turned upward and screened prior to entering the EDG room based on the building design, thus preventing missiles and precipitation from entering and adversely affecting EDG operation. Thus, the EDG combustion air intakes are protected from tornado-generated missiles and shielded from direct wind or rain. Air intake filters are also provided on the engine to remove particulates.

The EDG exhaust air system for each engine of the EDG set consists of an exhaust silencer and ducting. Exhaust bellows connect the engine housing to the exhaust system. The exhaust ducting exits to the roof and is sized to avoid excessive back-pressure Barrier hoods the protect roof exhausts from tornado winds and external missiles, as well as precipitation.

Air Starting System. Each EDG set has an independent air starting system. Each EDG is provided with two sets of two air receivers. Each set of air receivers has a sufficient air charge for starting a cold EDG set five times. Each EDG set is also provided with two air compressors; one is driven by a separate diesel engine and the other is driven electrically. These compressors provide charging air to the two sets of air receivers. The EDG sets are started by the air starting systems and do not depend on normal plant electrical power, except for the air start solenoid valves which require 125-V direct current (DC) power, or any other plant systems for starting operation.

Diesel Oil Fuel Supply System. The EDG fuel oil system is used to transfer diesel fuel oil from the onsite storage tanks to the day tanks which supply the EDG sets. Two completely redundant subsystems are provided, each consisting of a diesel oil storage tank, transfer pump, day tank, interconnecting piping and valves, and associated I&C. All electrical power necessary for operation of each subsystem is supplied from the associated EDG bus.

Lube Oil System. Each engine of each tandem EDG set has a self-contained lube oil system consisting of a lube oil sump located at the base of the engine, a fuel pump, a main engine lube and piston cooling pumps, cooling water pumps, a scavenging pump, AC and DC motor driven soakback pumps, filter, strainer, heat exchanger, and associated piping. The lube oil heat exchanger is served by the EDG set cooling water system. In the normal EDG operating mode, no external source of power or other plant system is required for the EDG set lube oil system. In the standby mode, the lube oil is constantly circulated by the AC soakback pump and warmed when the EDG is not operating. Warming is accomplished by passing the oil through the lube oil heat exchanger which receives warm water via immersion heaters. The DC soakback pump serves as the backup upon loss of the AC pump.

Cooling Water System. Each engine in each EDG set has a self-contained cooling system which consists of a forced circulation cooling water system which cools the engine directly, and an air-cooled radiator system which removes the heat from the cooling water. The system is pressurized but contains a surge tank for water expansion. The cooling water pump and radiator fan are driven directly from the engine crankshaft. After starting, the EDG set cooling system requires no external source of power and does not depend on any plant cooling system.

The applicant describes its process for identifying the mechanical components that are within the scope of license renewal in Section 2.1.2 of the LRA. EDGs and support systems are in the scope of license renewal because they contain SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related SCs, or SCs that are relied on during fire events and/or SBO events (Unit 1 only).

In Table 3.3-4 of the LRA, the applicant listed the component types for the EDGs and support systems that are subject to an AMR. The component types are Pumps, valves, air start motors (pressure boundary only), tanks, heat exchangers, silencers, flame arresters, filters, strainers, flexible hoses, expansion joints, orifices, thermowells, sight glasses, piping, tubing, and fittings. The intended functions for the EDGs and support systems components subject to an AMR include pressure boundary, filtration, heat transfer, throttling, and fire spread prevention.

2.3.3.4.2 Staff Evaluation

The staff reviewed Section 2.3.3.4 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the EDGs and support systems that are within the scope of license renewal, in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-4 of the LRA to determine whether the applicant appropriately identified the components of the EDGs and support systems that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the EDG system that were not listed in Table 3.3.4 of the LRA to verify that the applicant appropriately identified the components that meet the above requirements. The staff also reviewed Sections 8.3 and 9.5 of the UFSARs for Units 1 and 2, respectively, and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.4 of the LRA.

The staff verified that those portions of the EDGs and support systems identified by the applicant as meeting the scoping requirements of 10 CFR 54.4(a) do, in fact, meet these requirements for both units. The staff then focused its review on those portions of the EDGs and support systems that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4(a). The staff also reviewed Sections 8.3 and 9.5 of the UFSARs to identify system intended functions that were not included in the LRA and verified that these functions did not meet the scoping requirements of 10 CFR 54.4(a). Therefore, there is reasonable assurance that the applicant adequately identified all portions of the EDGs and support systems that are within the scope of license renewal in accordance with 10 CFR 54.4(a).

The staff then determined whether the applicant had appropriately identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the SCs that are subject to an AMR for the EDGs and support systems and listed them in Table 3.3-4 of the LRA. The staff performed its review by sampling the SCs that the applicant identified as within the scope of license renewal but not subject to an AMR to verify that these SCs perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period. Systems and components reviewed by the staff met the above criteria for Units 1 and 2.

In Table 2.3-3 of the LRA, the applicant lists seven license renewal boundary drawings for each unit that were highlighted to show the license renewal evaluation boundary for the EDGs and support systems. The staff compared the boundary drawings to the descriptions in the UFSARs to ensure that the boundary drawings were representative of the EDGs and support systems for the respective unit. The staff also sampled portions of the license renewal boundary drawings that were not highlighted to ensure that these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.3.4, the staff determined that additional information was needed to complete its review. In a letter dated July 18, 2002, the staff questioned the applicant about components that appeared to be subject to an AMR but were not included in Table 3.3-4 of the LRA. Specifically, the staff observed that duplex, lube oil, and Y strainers and immersion heaters were not included in Table 3.3-4 but were shown to be within the scope of license renewal on drawings 1-EDG-02, 1-EDG-03, 1-EDG-05, 1-EDG-06, 2-EDG-02, 2-EDG-03, 2-EDG-05, and 2-EDG-06 (RAI 2.3.3-2). In its response dated October 3, 2002, the applicant stated that the duplex and Y strainers were included in the "filter housings" component group and that the elements of lube oil strainers were included in the "filter elements" component group of Table 3.3-4. The staff finds the applicant's response acceptable on the basis that the response clarifies that these components are within the scope of license renewal and subject to an AMR.

As for the immersion heaters, the applicant stated that the heater housings are included in Table 3.3-4 of the LRA in the "piping/fittings" component group, and that the heater elements are considered electrical components. The applicant also stated that in accordance with Section 2.5 of the LRA, the heaters are considered to be active components, and therefore, no AMR is required. The staff finds the applicant's response in agreement with the staff position delineated in a letter dated September 19, 1997, from Christopher I. Grimes, U.S. NRC, to Mr. Douglas J. Walters, NEI, on the subject of "Determination of Aging Management Review for Electrical Components," and, therefore, considers the applicant's response to be acceptable.

The staff's review found that the components of the EDG and support systems that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.4.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the emergency diesel generator and support system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.5 Emergency Cooling Canal

2.3.3.5.1 Summary of Technical Information in the Application

In Section 2.3.3.5 of the LRA, the applicant identifies the structures of the emergency cooling canal and the mechanical components located in the ultimate heat sink (UHS) dam that are within the scope of license renewal and subject to an AMR. The emergency cooling canal is described in Section 9.2.7 of the Unit 1 UFSAR and Section 9.2.5 of the Unit 2 UFSAR.

The emergency cooling canal mechanical components, located at the UHS dam, have the intended function of providing a safety-related secondary supply of water to the UHS for St. Lucie Units 1 and 2. (The primary source of UHS water is the ocean intake structure and intake canal.) The UHS dam is located between the intake canal and Big Mud Creek, which is connected to the Atlantic Ocean through the Indian River tidal lagoon. The mechanical components admit water from Big Mud Creek through two parallel 137-cm (54-inch) pipes with butterfly valves that are normally closed by pneumatic operators and spring open upon loss of air supply. The structural components comprised by the emergency cooling canal and UHS dam are included in the civil/structural screening described in Sections 2.4.2.9 and 2.4.2.14 of the LRA, respectively.

The emergency cooling canal is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, or SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related SCs.

In LRA Table 3.3-5, the applicant listed the emergency cooling canal mechanical components subject to an AMR. These include valves (pressure boundary only), piping, and fittings. The applicant also identified the intended function of the emergency cooling canal mechanical components subject to an AMR as pressure boundary.

2.3.3.5.2 Staff Evaluation

The staff reviewed Section 2.3.3.5 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the emergency cooling canal that are within the scope of license renewal in accordance with 10 CFR 54.4(a) and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.5 of the LRA, the referenced site plan and piping and instrument drawings, and the UFSARs for both St. Lucie units to determine if the applicant adequately identified the portions of the emergency cooling canal that are within the scope of license renewal. The staff verified that the components of the emergency cooling canal that meet the scoping requirements of 10 CFR 54.4(a) were included within the scope of license renewal and subject to an AMR, as identified by the applicant in Table 3.3-5 of the LRA. The staff sampled those components of the emergency cooling canal that were not listed in LRA Table 3.3-2 to verify, with reasonable assurance, that the applicant properly identified the components that meet the criteria of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

As a result of this review, the staff questioned the applicant's omission from the scope of license renewal of certain safety-related air supply piping and components to the pneumatic actuators for the butterfly valves that control flow to the emergency cooling canal from Big Mud Creek. As detailed in the July 31, 2002, summary of the June 10—11, 2002, meeting, the applicant stated that the butterfly valves are designed to fail open. Loss of air to the butterfly valves would result in the valves opening and performing their intended function of providing a source of cooling water for plant shutdown. The staff therefore concurred with the omission of these components from the scope of license renewal on the basis that the air supply system does not provide any intended function that meets the scoping criteria of 10 CFR 54.4(a).

The staff review found that the SCs of the emergency cooling canal system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.5.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.5 of the LRA, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the emergency cooling canal system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Fire Protection

2.3.3.6.1 Summary of Technical Information in the Application

In Section 2.3.3.6 of the LRA, the applicant identifies the SCs of the fire protection system that are relied upon to demonstrate compliance with 10 CFR 50.48 and are within the scope of license renewal and subject to an AMR. The fire protection system is described in Appendix 9.5A, of the St. Lucie UFSARs for both units.

In accordance with 10 CFR 54.4(a)(3), the SSCs that are relied upon in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.48, the fire protection rule, are included within the scope of license renewal. An applicant is required to implement and maintain a fire protection program in accordance with the requirements stated in 10 CFR 50.48, to ensure safe plant shutdown in the event of a fire.

The fire protection system consists of subsystems for fire suppression water distribution and spray, RCP oil collection, and a Haloed system for the Unit 1 RAB cable spreading room.

In Section 2.5 of the LRA, the applicant states that fire detection is included in the electrical/I&C screening. Fire detection is provided in areas that contain or present a fire hazard to equipment essential to safe plant shutdown. The automatic fire detection system incorporates ionizationtype smoke detectors and thermal detectors capable of sensing fire in an early stage. The fire detection system gives audible and visual alarms in the control room, with local means provided to identify which detector has actuated. The fire detection system annunciation in the control room is distinctive and unique so as not to be confused with other plant system alarms.

The Haloed system provided in the Unit 1 cable spreading room is actuated by "cross-zoned" thermal detectors. Actuation of a thermal detector in Zone "1" will energize a visual light alarm on a local graphic annunciator panel and an audible alarm (pre-discharge horn strobe lamp). Actuation of the adjacent thermal detector in Zone "2" will energize the visual light alarm on the local graphic annunciator panel and will initiate the operation of the discharge alarm bell. In addition, a signal is transmitted to the Haloed control panel which will shut down the fan units, and melt the fusible links in the fire damper to allow dampers to close. The actuation of the detector in Zone "2" will also activate a 30-second release delay mechanism to provide time for final evacuation before to actual release of the Haloed.

Fire suppression includes the water distribution system, water spray and sprinkler systems, a Haloed system (Unit 1 cable spreading room), standpipe and hose system, and portable extinguishers. Self-contained breathing apparatus is also essential to the manual fire suppression efforts of the plant fire brigade.

The fire water system is common for both Unit 1 and Unit 2. The primary source of water for the fire water system is a tap from the city water system of Fort Pierce, Florida. This supply is capable of delivering 75.7 liters per second (L/s) at 276 to 310 kilopascals (KPa) (1200 gpm at 40 to 45 psi). This supply provides makeup water to two city water storage tanks (CWSTs) of 1893 m^3 (500,000 gallons) capacity, designed to ensure at least 757 m^3 (200,000 gallons) are maintained in each tank for FP. The CWSTs supply the intake for two electric-motor-driven fire water pumps, rated for 158 L/s at 862 kPa (2500 gpm at 125 psi).

The fire water system, when not operating, is kept pressurized by a hydropneumatic tank. 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. This tank pressure is maintained in the range of 756 to 963 kilopascals KPa (95 to 125 psig) by the domestic water pumps. If a manual or automatic fire suppression system is actuated, causing fire water system pressure to decrease, both fire pumps start automatically when header pressure drops to below 688 kPa (85 psig).

Fire suppression systems are provided in various plant areas to mitigate the consequences of fires. Four types of fixed fire suppression systems are used at St. Lucie, three of which are water based. Pre-action systems are used indoors for the protection of safety-related equipment. Wet pipe systems are used in the turbine building to protect non safety-related systems and to protect the two equipment hatches and the east stair Thermo-lag enclosure in the RAB. Fixed water spray systems are used in the yard to protect transformers and local hazards in the turbine building. The Haloed system is used to protect the RAB cable spread room.

The FP system contains SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components, or SCs that are relied on during fire events.

In Sections 2.1.1.4.1 and 2.3.3.6 of the LRA, the applicant identifies the source documents used in the FP scoping and screening effort as detailed in Appendix 9.5A of the UFSARs for Units 1 and 2, essential equipment lists, SSAs and St. Lucie licensing correspondence, design basis documents, component database, and design drawings. These documents and drawings were reviewed to identify the SCs of the fire protection system that perform the intended functions of fire detection, fire suppression, and fire barriers.

In Tables 3.3-6 and 3.5-8 of the LRA, the applicant listed the fire protection components subject to an AMR. These include tanks, pumps and valves (pressure boundary only), sprinkler heads, nozzles, vortex breakers, hydrants, flexible hoses, drip pans, orifices, piping, tubing, and fittings and fire doors. Hose stations are included as component types "nozzles" and "fittings," in Section 3.3 and listed in Table 3.3-6 of the LRA. Hose racks are included as component type "component supports (non safety-related)" in the civil/structural AMR in Section 3.5.2. In Tables 3.3-6 and 3.5-8 of the LRA, the applicant lists the intended functions for fire protection components subject to an AMR as pressure boundary, throttling, fire spread prevention, vortex prevention, and spray.

Other SSCs required for safe shutdown are addressed in the system of which they are a part. Fire-rated assemblies, fire barriers, and structural components required to ensure adequate Haloed concentrations are included in the civil/structural screening described in Section 2.4 of the LRA. Fire detection is included in the electrical/I&C screening described in Section 2.5. Features like sight glasses and flame arrestors associated with the EDGs are addressed with the EDGs and supporting systems (Section 2.3.3.4).

2.3.3.6.2 Staff Evaluation

The staff reviewed Sections 2.1.1.4.1 and 2.3.3.6 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the fire protection system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-6 of the LRA to determine whether the applicant appropriately identified the components belonging to the fire protection system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the FP system that were not listed in Table 3.3-6 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Appendix 9.5A of the St. Lucie Units 1 and 2 UFSARs and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.6 of the applicant's LRA.

Manual fire suppression is provided by standpipe and hose stations and portable extinguishers. LRA Section 2.3.3.6 states that fire extinguishers, fire hoses, and air packs are not subject to an AMR because they are replaced based on condition, in accordance with 10 CFR 54.21(a)(1)(ii). The standards that form the basis for plant surveillance procedures for fire protection equipment are NFPA 10, "Portable Fire Extinguishers"; NFPA 14, "Standpipe and Hose Systems"; and NUREG/CR-0041, "Manual of Respiratory Protection Against Airborne Radioactive Material."

The staff reviewed Tables 3.3-6 and 3.5-8 to determine whether the applicant appropriately identified the components belonging to the FP system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the FP system that were not listed in Tables 3.3-6 and 3.5-8 to verify that the applicant properly identified the components that meet the above requirements.

In a letter dated July 18, 2002, the staff asked the applicant to identify where the suppression systems for the cable spreading rooms are located on the license renewal boundary drawings or provide a description of the systems, since the staff could not locate these systems on the license renewal boundary drawings provided for the review (RAI 2.3.3-3).

By letter dated October 3, 2002, the applicant responded that there are no piping and instrument drawings for the Unit 1 Haloed system. This system is described in the St. Lucie Unit 1 UFSAR, Appendix 9.5A, Section 3.3. The Unit 2 cable spreading room pre-action sprinkler system is shown only on vendor drawings and, thus, was not included with the LRA boundary drawings. License renewal boundary drawings 1-FP-04 and 2-FP-01 show part of the supply piping to the pre-action system, and Note 1 on these drawings explains that the remainder of the system is shown on vendor drawings. The Unit 2 cable spreading room pre-action sprinkler system is described in the Unit 2 UFSAR, Appendix 9.5A, Section 3.3. All passive, long-lived components associated with the Unit 1 Haloed system and Unit 2 cable spreading room pre-action sprinklers are included in Table 3.3-6, except for the Haloed system nitrogen tank discussed below. The staff finds the applicant's response to be acceptable on the basis that it identified acceptably detailed descriptions of the components of the Haloed and pre-action sprinkler systems.

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 the staff has identified the hydropneumatic tank and appurtenances (provides pressure maintenance for fire water system) and nitrogen tank for gaseous extinguishing 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.

In a letter dated July 18, 2002, the applicant was asked to clarify the CLB, consistent with 10 CFR 50.48, with respect to scoping for license renewal, and to justify why SSCs listed in the UFSAR are considered to be outside the scope of license renewal (RAI 2.3.3-15).

By letter dated October 3, 2002, the applicant responded that the hydropneumatic tank was determined not to be in the scope of license renewal because the hydropneumatic tank does not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff evaluated the applicant's position concerning the hydropneumatic tank and studied the relevant documents in NFPA 20; the St. Lucie UFSAR, Appendix 9.5A for both units; the Unit 1 UFSAR, Section 9.2.6.2; the Unit 2 UFSAR, Section 9.2.4.2; and the associated SERs. The staff concluded, based upon this review, that the pressure maintenance function provided by the hydropneumatic tank at the St. Lucie site serves in lieu of the jockey pumps/pressure maintenance device required by NFPA 20. The requirement for the jockey pumps/pressure maintenance device is stated in Section 31(e) of the 1972 edition of NFPA 20, cited by the St. Lucie UFSARs as part of the original licensing basis for the plant. The staff based this conclusion, in part, on the fact that the hydropneumatic tank and its associated domestic water pumps and piping perform a pressure maintenance function which protects the large fire pumps from damage during low-flow-high-pressure operation. The staff, therefore, disagrees with the applicant's response to RAI 2.3.3-15 concerning the hydropneumatic tank.

The applicant decided to supplement its response to RAI 2.3.3-15 by letter dated November 27, 2002, to include the hydropneumatic tank, as well as the domestic water pumps, associated valves, and piping/fittings that supply makeup water to this tank in Table 3.3-6.

Some of the boundaries established in the pressure maintenance system are not closed valves. The hydropneumatic tank contains a low-pressure switch which initiates an alarm upon low pressure. Plant operators periodically check the hydropneumatic tank and domestic water pumps for abnormal conditions. If a break were to occur downstream of these boundaries, the break could be isolated at the valves located at the boundaries. Also, in the event of a drop in pressure in the fire protection pressure maintenance system to below the starting pressure of the fire pumps, the fire pumps would start. Throughout this transient, pressure would be maintained on the fire protection system. Plant experience indicates that any negative effects of an occasional transient of this type would be minimal. The staff has reviewed this justification for license renewal boundaries at open valves and finds it acceptable.

Regarding the nitrogen tank, the applicant's October 3, 2002, response stated that Appendix 9.5A of the Unit 1 UFSAR, 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 of the LRA. Table 3.3-6 has been modified to include it. The staff finds the applicant's response to be acceptable, on the basis that this component is included within the scope of license renewal and subject to an AMR.

The applicant responded that the Haloed system in the Unit 1 cable spreading room was in scope, although it does not appear on the P&IDs.

The staff finds the applicant's response to RAI 2.3.3-15 concerning the hydropneumatic tank, nitrogen tank, and Haloed system to be acceptable on the basis that these components are included within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

The staff review found that the components of the FP system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). On the basis of its review of the information presented in Section 2.3.3.6 of the LRA, the UFSARs, and the applicant's responses to the staff's RAIs, the staff did not identify any omissions.

2.3.3.6.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the fire protection system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.7 Fuel Pool Cooling

2.3.3.7.1 Summary of Technical Information in the Application

In Section 2.3.3.7 of the LRA, the applicant identifies the components of the fuel pool cooling system that are within the scope of license renewal and subject to an AMR. These systems are further described in Section 9.1.3 of the UFSARs for Units 1 and 2. During normal operation, fuel pool cooling removes decay heat from the fuel pool by circulating water from the/Intake cooling water system through the fuel pool heat exchangers. The heat from the fuel pool is transferred to the component cooling water.

The safety-related means of fuel pool cooling for Unit 1 is pool boiloff and addition of makeup water without forced circulation through the heat exchanger. The safety-related means of fuel pool cooling for Unit 2 is recirculation through the fuel pool heat exchangers. As a backup, Unit 2 fuel pool cooling can be accomplished by pool boiloff and addition of makeup water from the intake cooling water system.

The applicant describes its process for identifying the mechanical components that are within the scope of license renewal in Section 2.1.2 of the LRA. Fuel pool cooling is in the scope of license renewal because it contains SCs that are safety-related and are relied upon to remain functional during and following DBEs and SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions of SCs.

The applicant listed the types of fuel pool cooling components that are subject to an AMR in Table 3.3-7 of the LRA. They include pumps and valves (pressure boundary only), heat exchangers, thermowells, piping, tubing, and fittings. The intended functions for fuel pool cooling components subject to an AMR include pressure boundary and heat transfer (Unit 2 only).

2.3.3.7.2 Staff Evaluation

The staff reviewed Section 2.3.3.7 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the fuel pool cooling system within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff reviewed Section 2.3.3.7 of the LRA and the UFSARs to determine whether any SC portions of the fuel pool cooling system may meet the scoping criteria in 10 CFR 54.5(a) that have been omitted from the scope of license renewal. Accordingly, the staff focused its review on those portions of the fuel pool cooling system that were not identified by the applicant as within the scope of license renewal to determine whether they meet the scoping requirements of 10 CFR 54.4 (a). The staff also reviewed Section 9.1.3 of the UFSARs for Units 1 and 2 to identify system intended functions that were not included in Section 2.3.3.7 of the LRA and verified that these functions did not meet the scoping requirements of 10 CFR 54.4(a).

The staff then determined whether the applicant had appropriately identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the SCs that are subject to an AMR for the fuel pool cooling system and listed them in Table 3.3-7. The staff performed its review by sampling the SCs that the applicant identified as within the scope of license renewal but not subject to an AMR to verify that these SCs perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period. SCs reviewed by the staff met the above criteria for Units 1 and 2.

In Table 2.3-3 of the LRA, the applicant lists one license renewal boundary drawing for each unit that was highlighted to show the license renewal evaluation boundary for the fuel pool cooling system. The staff compared the boundary drawings to the descriptions in the UFSARs for Units 1 and 2 to ensure that the boundary drawings were representative of the fuel pool *cooling system for the respective unit. The staff also sampled portions of the boundary* drawings that were not highlighted to determine whether any of these components perform an intended function associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.3.7, the staff determined that additional information was needed to complete the review. At Unit 1, the makeup water sources include the refueling water storage tank via the fuel pool purification pump and the primary water tank. At Unit 2, makeup to the fuel pool is also provided from the refueling water tank via the refueling water pool purification pump and from the primary water tank. The UFSARs for Units 1 and 2 describe these makeup sources; however, license renewal boundary drawings 1-SFP-01 and 2-SFP-01 do not show the piping and valves associated with the makeup line from the refueling water storage tank or the primary water tank to be within the scope of license renewal. In a letter dated July 18, 2002, the staff asked the applicant to justify why the piping and valves are considered not within the scope of license renewal and therefore not subject to an AMR (RAI 2.3.3-4).

By letter dated October 3, 2002, the applicant responded by referring to Section 9.2.3 of the *original SER for Unit 1 which states that a fire hose can be connected to the seismic Category I* intake cooling water system at two points to provide makeup. The original SER stated further that if NRC review indicated that unacceptable damage could be caused, the fuel exposed to salt water would not be reloaded into the reactor, and that, on the basis of this requirement, the design was acceptable. The results of further NRC review are discussed in Supplement 1 to this SER. Section 9.2.3 of Supplement 1 to this SER states that this evaluation was performed, and that for the anticipated time that the salt water makeup would be in use, no unacceptable corrosion of fuel elements or support structures would occur. On the basis of additional information provided, the NRC also concluded that it would be unlikely that the sea water method of cooling would be needed since several other makeup sources are available.

The applicant also referred to portions of the UFSAR for each unit. After describing the availability of makeup from the refueling water storage and primary water tanks, both UFSARs for Units 1 and 2 describe the intake cooling water source of makeup water as a seismic Category I backup supply of spent fuel pool makeup water. The applicant noted that only salt water makeup from intake cooling water is credited in the safety analysis for makeup to the Unit 1 and Unit 2 spent fuel pools.

After reviewing the applicant's response, the staff consulted the NRC correspondence archive to clarify the basis for conclusions presented in the original SER and SER supplements. On June 7, 1974, FPL submitted a response to NRC questions entitled, "Amendment 26 to the Final Safety Analysis Report." In Question 9.6, the NRC stated that the non-seismic Category I classification of those portions of the fuel pool system which perform the cooling function is *unacceptable. In response, FPL committed to provide a seismic connection on each intake* cooling water header in the component cooling water heat exchanger area, a standpipe on the fuel handling building from grade to the operating deck elevation, and seismic connections at both ends of the standpipe. The FPL response concluded, "Thus, via [sic] firehose, the fuel pool makeup can be readily supplied by the intake cooling water pumps. The head provided by these pumps is sufficient."

The applicant's 1974 addition of the seismically qualified, temporary connections to the (salt water) intake cooling water system as a makeup source responded to the concern that the cooling system for Unit 1 was not seismically qualified. However, as discussed in the SERs and

UFSARs for Units 1 and 2, the availability of diverse fresh water sources make the use of this salty water source unlikely.

Although the UFSARs and previous staff evaluations for St. Lucie Units 1 and 2 include the fresh water sources as the preferred method to mitigate a loss of spent fuel pool coolant inventory, the staff previously concluded that the addition of salt water from the intake cooling water system can be aligned in sufficient time and provide adequate makeup capacity to assure an adequate coolant inventory is maintained in the spent fuel pool. Therefore, this makeup path alone is sufficient to satisfy the LR scoping criteria of 10 CFR 54.4 (a)(1). The freshwater makeup sources provide a redundant capability that is not required to be within the scope of LR in accordance with 10 CFR 54.4 (a)(2).

During a telephone call on February 3, 2003, the applicant agreed to resubmit its October 3, 2002, response to RAI 2.3.3-4. At the request of the staff, the applicant agreed to remove the paragraphs that contained the applicant's assessment of the plant design as referenced in the UFSARs and to state that the intake cooling water makeup to the spent fuel pool meets the scoping requirement of 10 CFR 54.4. This was Confirmatory Item 2.3.3.7-1.

By letter dated March 28, 2003, the applicant provided a supplemental response to RAI 2.3.3-4. This response describes the CLB with respect to spent fuel pool makeup capability based on the aforementioned licensing correspondence, dated June 7, 1974. As described above, this information provided an adequate basis to conclude that the screening criteria of 10 CFR 54.4(a)(1) are satisfied by the makeup lines from the intake cooling water system. Therefore, the staff considers Confirmatory Item 2.3.3.7-1 to be closed.

The staff conducted an on site inspection, which included verifying the material condition of the intake cooling water (ICW) makeup system for the spent fuel pools. The applicant had identified weaknesses associated with the system and had entered the weaknesses in its corrective action program. The inspection was completed on January 31, 2003. The staff's review of the inspection findings was Open Item 3.0.2.2-1.

The staff reviewed Inspection Report Nos. 50-335/2003-03 and 50-389/2003, issued on March 7, 2003, and concluded that the weaknesses associated with the ICW makeup system constitute current licensing issues, which will be resolved by the Region II staff, rather than license renewal issues. Therefore, consistent with the corrective actions agreed to by the licensee, the ICW makeup lines to the fuel handing buildings will be adequately managed over the period of extended operation. The staff considers Open Item 3.0.2.2-1 closed.

The staff compared the components listed in Table 2.3.3-7 of the LRA to those highlighted in the drawings and found them consistent with the components highlighted in the license renewal boundary drawings. The staff review found that the components of the fuel pool cooling system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.7.3 Conclusions

With the satisfactory resolutions of Open Item 3.0.2.2-1 and Confirmatory Item 2.3.3.7-1, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the fuel pool cooling system components subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.3.3.8 Instrument Air

2.3.3.8.1 Summary of Technical Information in the Application

In Section 2.3.3.8 of the LRA, the applicant identifies the components of the instrument air system that are within the scope of license renewal and subject to an AMR. This system is further described in Section 9.3.1 of the UFSARs for both St. Lucie Units 1 and 2.

The instrument air system has the intended function of providing a reliable source of dry, oil-free air for I&C and pneumatic valves. Instrument air provides motive power and control air to safety-related and non safety-related components. Only a limited number of components in the scope of license renewal require instrument air to perform their intended function. Therefore, only those portions of the system that are in the main flow path from the instrument air compressors to the applicable components are designated as within the scope of license renewal.

The applicant states that some of the license renewal boundaries of the instrument air system were established at normally open valves. The following reasons explain why the applicant considers this approach acceptable for the instrument air system.

- Instrument air supplies air to many active components required for normal plant operation, and loss or reduction of air pressure due to degraded conditions is detected early.
- Instrument air is predominantly constructed of galvanized carbon steel and bronze with an internal environment of dry air, making it very resistant to general corrosion.
- The limited number of valves that rely on instrument air are required only for maintaining hot standby conditions for SBO events or achieving cold shutdown during and following design-basis fires. Both of these situations would permit ample time for manual isolation of portions of instrument air not within the scope of license renewal, if required.

Instrument air is in the scope of license renewal because it contains structures or systems that are safety-related and are relied upon to remain functional during and following DBEs, and others that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related structures or systems. Instrument are also contains structures or systems that are part of the EQ Program, are relied on during fire events, and are relied on during SBO events (Unit 1 only).

In Table 3.3-8 of the LRA, the applicant listed the component types for the instrument air system that are subject to an AMR. They include valves (pressure boundary only), receivers, accumulators, dryers, filters, strainers, heat exchangers, flexible hoses, orifices, silencers, thermowells, sight glasses, rupture discs, piping, tubing, and fittings. The intended functions for instrument air components subject to an AMR include pressure boundary, heat transfer, filtration, and throttling.

2.3.3.8.2 Staff Evaluation

The staff reviewed Section 2.3.3.8 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the components of the instrument air system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-8 of the LRA to determine whether the applicant adequately identified the components of the instrument air system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the instrument air system that were not listed in Table 3.3-8 to verify that the applicant appropriately identified the components that meet the above requirements. The staff also reviewed Section 9.3.1 of the UFSARs for Units 1 and 2 and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.8.

In Table 2.3-3 of the LRA, the applicant lists several license renewal boundary drawings for each unit that were highlighted to show the license renewal evaluation boundary for the instrument air system. The staff compared the boundary drawings to the descriptions in the UFSARs to ensure that the boundary drawings were representative of the instrument air system for the respective unit. The staff also sampled portions of the boundary drawings that were not highlighted to ensure these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.3.8 of the LRA, the staff determined that additional information was needed to complete its review. In a letter dated July 18, 2002, the staff questioned the applicant about components that appeared to be subject to an AMR but were not included in Table 3.3-8 of the LRA. Specifically, the staff observed that an oil/water separator (license renewal boundary drawing 1-IA-06 at location F6), moisture separators (license renewal boundary drawing 1-IA-06 at locations C3 and E3 and license renewal boundary drawing 2-IA-04 at locations B3 and D3), and oil coolers (license renewal boundary drawing 2-IA-04 at locations F2 and H2) were not included in Table 3.3-8. In its response dated October 3, 2002, the applicant clarified that the oil/water separator and moisture separators are included in the component group "filters" and are listed in Table 3.3-8 of the LRA. The applicant stated that the oil coolers in question are internal to the compressors and were thus treated as integral parts of the compressor. Since the instrument air compressors are active components, they are not subject to an AMR which is consistent with the requirements of 10 CFR 54.21 (a)(1)(i) and the guidance of NEI 95-10. The staff finds the applicant's response to be acceptable on the basis that the oil coolers are an integral part of the air compressors, which are considered an active component, in accordance with the requirements of 10 CFR 54.21 (a)(1)(i) and the guidance of NEI 95-10.

The staff also questioned the exclusion from an AMR of instrument air dryers at Unit 2 (license renewal boundary drawing 2-IA-04). In Section 9.3.1 of the UFSARs for Units 1 and 2, the applicant discusses the ability to cross-connect the instrument and station air systems for Units 1 and 2. In its response dated October 3, 2002, the applicant explained why the Unit 2 instrument air compressors and air dryers are not relied on to perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a) for Unit 2. In its explanation, the applicant stated that the Unit 2 instrument air compressors 2A and 2B are included in the scope of license renewal because they are credited for supplying air for isolation of the Unit 1 Feedwater control valves during certain postulated fire events on Unit 1. The Unit 2 air dryers are located downstream of the cross-connect line to Unit 1 (license renewal boundary drawing 2-IA-04 at location F7) and are not in service during this operational alignment. Therefore, the Unit 2 air dryers are not within the scope of license renewal. The staff finds this response to be acceptable on the basis that it clarifies that the instrument air dryers at Unit 2 do not perform an intended function within the scope criteria of 10 CFR 54.4(a).

Related to this issue, the staff questioned why piping and components associated with two of the Unit 1 air compressors (air compressors 1C and 1D) are considered to be outside the scope of license renewal. In its response dated October 3, 2002, the applicant stated that during a Unit 1 SBO event, Unit 1 instrument air compressors 1C and 1D do not operate since they are supplied by non vital power. Unit 1 instrument air compressors 1A and 1B are, however, credited for a Unit 1 SBO event because they can be manually loaded onto a vital bus and powered via the 4-kV cross-tie from Unit 2 by one of the two Unit 2 EDGs. Therefore, Unit 1 instrument air compressors 1C and 1D are not required to perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). On the basis of the explanation provided and the criteria set forth in 10 CFR 54.4(a), the staff finds this response to be acceptable.

As discussed above, the applicant stated in Section 2.3.3.8 of the LRA that some of the license renewal boundaries for the instrument air system were established at normally open valves and justified this action. The staff observed that in certain cases, failure of the downstream piping may affect the pressure boundary intended function. On July 18, 2002, the staff asked the applicant to provide additional information to support the basis for its determination that it was acceptable for boundaries to be at normally opened valves, such as information about whether SBO and fire procedures specified closing these valves, the amount of time required to complete procedure actions, and the availability of sufficient air inventory if the valves are not closed.

In its response dated October 3, 2002, the applicant reiterated the information stated in the LRA (presented above) and provided the following new information:

> Instrument air boundaries have been established at the first manual isolation valves on branch lines off of these required flow paths. It is not expected that these open valves would actually require closing, only that sufficient time exists if closure was needed. Therefore, procedure changes are not required. Although these boundary valves are normally open, they are considered acceptable license renewal boundaries because instrument air is designed with substantial redundancy and capacity.

The staff finds the applicant's response acceptable on the basis that the instrument air system is designed with substantial redundancy and capacity which permits ample time for manual isolation, if required, of portions of instrument air not within the scope of license renewal.

The staff's review found that the SCs of the instrument air system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.8.3 *Conclusions*

The staff concludes that there is reasonable assurance that the applicant has appropriately identified instrument air system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 Intake Cooling Water

2.3.3.9.1 Summary of Technical Information in the Application

In Section 2.3.3.9 of the LRA, the applicant identifies the components of the ICW system which are within the scope of license renewal and subject to an AMR. The ICW system is described in Section 9.2.1 of the Units 1 and 2 UFSARs.

The ICW system has the intended function of removing heat from the component cooling water and turbine plant cooling water. The ICW pumps supply salt water from the intake canal for each unit through two redundant piping headers per unit on the tube side of the component cooling water and turbine cooling water heat exchangers. The component cooling water heat exchangers are considered part of the component cooling water system and were screened with that system (see SER Section 2.3.3.2). The turbine cooling water heat exchangers are considered part of the turbine cooling water system and were screened with that system (Unit 1 only, see SER Section 2.3.3.14). After flowing through the heat exchangers, the intake cooling water is discharged to the discharge canal. The intake cooling water has the additional intended function of providing a safety-related makeup water source for fuel pool cooling (described in SER Section 2.3.3.7).

The ICW system is in the scope of license renewal because it contains SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related structures or components, and SCs that are relied on during fire events.

Based on the intended functions previously identified, the applicant listed the ICW system components subject to an AMR in Table 3.3-9. They include pumps and valves (pressure boundary only), strainers, expansion joints, thermowells, orifices, piping, tubing, and fittings. In that table, the applicant identified the intended functions for the ICW components subject to an AMR as pressure boundary, filtration, and throttling.

2.3.3.9.2 Staff Evaluation

The staff reviewed Section 2.3.3.9 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the ICW system that are within the scope of license renewal in accordance with 10 CFR 54.4(a) and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.9 of the LRA, the referenced site plan and piping and instrument drawings, and the UFSARs for both St. Lucie units to determine if the applicant adequately identified the portions of the ICW system that are within the scope of license renewal. The staff verified that the components of the ICW system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and are subject to an AMR, as identified by the applicant in Table 3.3-9 of the LRA. The staff sampled those components of the ICW system that were not listed in LRA Table 3.3-9 to verify, with reasonable assurance, that the applicant properly identified the components that meet the scoping criteria of 10 CFR 54.4.

As a result of this review, the staff questioned the applicant's omission from the scope of license renewal of certain safety-related components. By letter dated July 18, 2002, the staff requested the applicant to justify the omission of the stationary and traveling screens located at the rear of the intake structure, prior to the inlet to the ICW pumps. The staff believes that these screens prevent debris and organisms from causing the failure of the safety-related ICW pumps and strainers. As such, these screens would be within the scope of license renewal and subject to an AMR.

The applicant responded to this request on October 3, 2002, by stating that the stationary and traveling screens were determined not to be within the scope of license renewal because they do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). These components support normal plant power operation, but their failure does not affect the safety-related function of ICW. During plant power operation, the non safety-related circulating water pumps draw a significant flow of cooling water through the intake structure to support main condenser cooling requirements. This high flow rate creates the potential for debris or organisms to enter the intake. As a result, stationary and traveling screens are provided to enhance the reliability of plant power operation. In comparison to the circulating water pumps, the safety-related ICW pumps draw a small amount of cooling water through the intake. Any significant degradation or failures of the screens during power operation would be evident and detected by plant operators far in advance of a complete failure. Even in case of total failure, floating or heavy debris would not affect ICW pump operation due to the low velocities at the suction of the ICW pumps. As discussed in Section 9.2.1.3 of the Units 1 and 2 UFSARs, the ICW pumps and heat exchangers are evaluated for design-basis accident heat removal with suspended materials of up to 1.3 cm (½ inch) and silt. Additionally, the component cooling water heat exchangers are protected from suspended solids by the basket strainers (which have differential pressure alarms in the control room) that are included in LRA Table 3.3-9 (pages 3.3-59 through 3.3-62). During emergency operation, the flow velocities in the vicinity of the stationary and traveling screens will be less than 4 centimeters/per second (cm/sec) (0.13 ft/sec).

The staff evaluated the applicant's response and concurs that during emergency operation, the low inlet flow velocity precludes the possibility of blockage due to silt and heavy debris buildup. Only light objects or suspended solids will be entrained into the intake flow; these will be caught in the basket strainers. Therefore, the stationary and traveling screens do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). On the basis stated above, the staff finds the exclusion of these components from the scope of license renewal to be acceptable.

In the same July 18, 2002, letter, the staff also requested the applicant to justify the omission from LRA Table 3.3-9 of the temporary hoses used to provide the safety-related makeup water connection from the ICW system to the spent fuel pool (SFP) as described in Section 9.1.3.4.3.2 of the Unit 1 UFSAR. In its October 3, 2002 response, the applicant stated that hoses may be temporarily connected and utilized to provide makeup water to the SFP as a backup water source. Similar hose connections exist on the Unit 2 ICW and SFP cooling systems (Unit 2 UFSAR, Section 9.1.3). The hoses used for these connections are fire hoses obtained from any site fire hose house. As stated in Section 2.3.3.6 (page 2.3-19) of the LRA, fire hoses are within the scope of license renewal, but they are replaced on condition in accordance with NFPA guidelines and therefore, are not subject to an AMR.

The staff concurs with the applicant's exclusion of the fire hoses on the basis that these components are subject to replacement based on a qualified life or specified time period and, as such, do not meet the criteria for being subject to an AMR stated in 10 CFR 54.21(a)(1)(ii).

The staff review found that the components of the ICW system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.9.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the ICW system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.10 Miscellaneous Bulk Gas Supply

2.3.3.10.1 Summary of Technical Information in the Application

In Section 2.3.3.10 of the LRA, the applicant identifies the components of the miscellaneous bulk gas supply (MBGS) that are within the scope of license renewal and subject to an AMR. The MBGS storage facility is common to both units. This system is further described in Section 9.3.1 of the St. Lucie Unit 1 UFSAR.

The MBGS system has the intended function of supplying hydrogen, carbon dioxide, and nitrogen required for plant operation. The MBGS consists of various storage facilities and associated components. Facilities for bulk storage of hydrogen in tube trailers and bottles is located approximately 120 feet north of the Unit 1 intake structure. Carbon dioxide is stored in bottles in the gas storage building, which is located adjacent to the bulk hydrogen storage facility. Bulk storage facilities for nitrogen are provided by a low-pressure nitrogen Dewar with two compressors and a high-pressure tube trailer.

The MBGS is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related SCs, and SCs that are relied on during fire events.

On the basis of the intended functions, the applicant listed the MBGS component types that are subject to an AMR in Table 3.3-10 of the LRA. They include valves (pressure boundary only), vessels, piping, tubing, and fittings. The intended function for MBGS components subject to an AMR is pressure boundary.

2.3.3.10.2 Staff Evaluation

The staff reviewed Section 2.3.3.10 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the MBGS within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff reviewed Section 9.3.1 of the Unit 1 UFSAR to determine whether any SCs of the MBGS that meet the scoping criteria in 10 CFR 54.4(a) may have been omitted from the scope of license renewal. The staff verified that those portions of the MBGS identified by the applicant as meeting the scoping requirements of 10 CFR 54.4(a) do, in fact, meet these requirements for both units. The staff then focused its review on those portions of the MBGS that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4(a). The staff also reviewed Section 9.3.1 of the St. Lucie Unit 1 UFSAR to identify system intended functions that were not included in Section 2.3.3.10 of the LRA and verified that these functions did not meet the scoping requirements of 10 CFR 54.4(a). Therefore, there is reasonable assurance that the applicant appropriately identified portions of the MBGS that are within the scope of license renewal in accordance with 10 CFR 54.4(a).

The staff then determined whether the applicant had appropriately identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). In Table 3.3-10 of the LRA, the applicant identified the SCs that are subject to an AMR for the MBGS. The staff performed its review by sampling the SCs that the applicant identified as within the scope of license renewal but not subject to an AMR to verify that these SCs perform their intended functions with moving parts or with a change in configuration or properties or are subject to replacement based on qualified life or specified time period. Structure and components reviewed by the staff met the above criteria.

In Table 2.3-3 of the LRA, the applicant listed four license renewal boundary drawings that were highlighted to show the license renewal evaluation boundary for the MBGS. The staff compared the boundary drawings to the description in the UFSAR to ensure that the boundary drawings were representative of the MBGS for Units 1 and 2. The staff also sampled portions of the boundary drawings that were not highlighted to ensure that these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.3.10, the staff determined that additional information was needed to complete its review. The description provided in the Unit 1 UFSAR is limited. In addition, the referenced drawings are for various other systems which also include a portion of the MBGS. Therefore, the staff could not determine with reasonable assurance that the applicant had correctly identified the components that are within the scope of license renewal for the MBGS. In a letter dated July 18, 2002, the staff asked the applicant to provide a more detailed description of the MBGS and additional information concerning the design and intended functions of the MBGS system. In its response dated October 3, 2002, the applicant stated that portions of the MBGS penetrate the containments and thus provide a containment integrity function. The MBGS isolation valves that perform a containment integrity function are shown on license renewal boundary drawings 1-SAMP-02 (V29217, V29324, V29213, V29334, V29305, and V29306) and 2-SAMP-03 (V29455, V29434, and V29456). Additionally, portions of the MBGS form part of the boundary of interfacing safety-related components and thus provide a safety-related pressure boundary function (Unit 2 nitrogen supply to the containment spray hydrazine storage tank, valve V29431, and downstream piping on drawing 2-CS-01).

In addition, the applicant stated that the MBGS is relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (e.g., limiting hydrogen concentration anywhere in the Unit 2 RAB to less than 2 percent in the event of a hydrogen pipe rupture). Therefore, the excess flow isolation valve, V29462, and associated upstream piping and valves (license renewal boundary drawing 2-IA-05) are in the scope of license renewal.

The staff's review found that the components of the MBGS that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.10.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified MBGS components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 Primary Makeup Water

2.3.3.11.1 Summary of Technical Information in the Application

In Section 2.3.3.11 of the LRA, the applicant identifies the components of the primary makeup water system that are within the scope of license renewal and subject to an AMR. The system is described in Section 9.2.5 of the Unit 1 UFSAR and Section 9.2.3 of the Unit 2 UFSAR.

The primary makeup water system provides treated, demineralized water of the required quality for makeup to various systems throughout the plants. The primary makeup water system piping penetrates the containments and functions as a part of the containment pressure boundary for both units. For Unit 2, the primary makeup water system intended functions also include FP and EQ.

The primary makeup water system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related structures or components, and SCs that are part of the EQ Program (Unit 2 only) or relied upon during certain fire events (Unit 2 only).

The applicant listed the primary makeup water system component types subject to an AMR. They include tanks, pumps, and valves (pressure boundary only), nozzles, vortex breakers, expansion joints, orifices, piping, tubing, and fittings. As discussed in Section 2.1 of this SER, the applicant identified additional pipe/fittings and valves of the primary makeup water system as subject to an AMR in its September 26, 2002, response to RAI 2.1-1. The intended functions for primary makeup water components subject to an AMR include pressure boundary, vortex prevention, spray, and throttling.

2.3.3.11.2 Staff Evaluation

The staff reviewed Section 2.3.3.11 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the primary makeup water system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-11 of the LRA to determine whether the applicant appropriately identified the components of the primary makeup water system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the primary makeup water system that were not listed in Table 3.3-11 of the LRA to verify with reasonable assurance that the applicant appropriately identified the components that meet the above requirements. The staff also reviewed Section 9.2.5 of the Unit 1 UFSAR and Section 9.2.3 of the Unit 2 UFSAR and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.11 of the LRA.

The staff requested clarification of several items regarding the primary makeup water system as detailed in the July 31, 2002 summary of the June 10—11, 2002, meeting. The applicant clarified the location of a vortex breaker in the 150,000-gallon primary water storage tank (license renewal boundary drawing 2-PW-01) as on top of the drain pipe that extends into the primary cooling water storage tank. The clarification was needed because the symbol for the vortex breaker is not included on the "General Notes and Legend" license renewal boundary drawing.

At the same June 10 meeting, the staff also questioned whether pieces of a failed floating diaphragm in the primary water storage tank (license renewal boundary drawing 2-PW-01 at location A3) could enter the tank and prevent the vortex breaker from performing its intended function and/or limit the availability of water for FP purposes. The applicant stated that the diaphragm is metal and, therefore, is unlikely to break into pieces (documented in the June 10–11, 2002, meeting summary dated July 31, 2002). The staff finds the applicant's response to be acceptable on the basis that industry experience has not shown that metal diaphragms or vortex breakers fail in a manner that impairs the ability of the primary water tank to supply water for its intended function of FP.

License renewal boundary drawing 2-PW-01 at location B3 shows a manway on the primary water storage tank (license renewal boundary drawing 2-PW-01 at location B3). The staff questioned the applicant about why the seals and cover for this manway are not listed in Table 3.3-11 of the LRA as being within the scope of license renewal and subject to an AMR. The applicant stated that the information requested by the staff is contained in Table 3.3-11 on page 3.3-69 and in Appendix C on page C-16 of the LRA. The applicant further stated that loss of mechanical closure integrity is an aging effect associated with bolted mechanical closures that results in failure of the mechanical joint. The manways are evaluated under the AMR for bolting (mechanical closures). The staff finds the applicant's response to be acceptable on the basis that the clarification provided identified that the aging of these bolted closure components will be evaluated in an AMR.

During the review, the staff met with the applicant to request clarification of the description for the component types listed in the LRA. As documented in the summary of the June 10—11, 2002, meeting dated July 31, 2002, the applicant explained that manway covers and associated seals, such as that attached to the primary water storage tank (license renewal boundary drawing 2-PW-01 at location B3), are listed in Table 3.3-11 of the LRA as "bolting" (mechanical closures). The applicant also stated that hose stations in the Unit 2 containment and the Unit 2 fuel handling building are included as component groups "nozzles" and "fittings," shown in Table 3.3-11, and that hose racks are included as component group "component supports (non safety-related)" in the civil/structural AMR in Section 3.5 of the LRA and shown in Tables 3.5-2 and 3.5-9 of the LRA.

After completing the initial review, by letter dated July 18, 2002, the staff requested additional information regarding the primary makeup water system. Specifically, the staff questioned the applicant about why the in-scope boundary of the primary makeup water system ends at valves that are shown as normally open (license renewal boundary drawing 2-PW-01 at locations H4 and H5). In Section 2.3.3.11, "Primary Makeup Water," of the LRA, the applicant states that this approach is acceptable because Unit 2 primary makeup water is required only in the event of a fire in the Unit 2 containment or Unit 2 fuel handling building, and the open boundary valves are closed for these fire scenarios. The staff requested that the applicant provide additional information to support the basis for this determination.

The applicant responded to the above questions by letter on October 3, 2002, and stated that valves V15518, V15353, and V15579 are normally open valves. In order to ensure the flow path for the Unit 2 primary makeup water FP function, these valves are procedurally controlled such that they will be closed, if previously open, when primary makeup water is required for the hose stations inside the Unit 2 containment. Additionally, even though valve HCV-15-1 is a primary containment isolation valve, it must also be open when primary makeup water is required for the hose stations. Therefore, valve HCV-15-1 is also procedurally controlled such that it is manually opened, if closed, when primary makeup water is required for these hose stations.

The staff finds the applicant's response to be acceptable on the basis that closure (and opening) of the valves described above is controlled by FP procedures which were developed and reviewed by site safety personnel and are available for inspection by the staff.

The staff's review found that the SCs of the primary makeup water system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.11.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the primary makeup water system components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.12 Sampling System

2.3.3.12.1 Summary of Technical Information in the Application

In Section 2.3.3.12 of the LRA, the applicant identifies the components of the sampling system that are within the scope of license renewal and subject to an AMR. The system is described in Section 9.3.2 of the Unit 1 UFSAR and Section 9.3.2 of the Unit 2 UFSAR.

The sampling system provides the means to obtain samples from the RCS and auxiliary systems during all modes of plant operation for chemical and radiological analysis.
A portion of the sampling system piping penetrates the containment and, therefore, provides the intended function of containment pressure boundary for both units.

The sampling system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended function of safety-related SCs , SCs that are a part of the EQ Program (Unit 2 only), SCs that are relied upon during fire events, and SCs that are relied upon during SBO events (Unit 1 only).

In Table 3.3-12 of the LRA, the applicant listed the sampling system component types subject to an AMR. They include valves (pressure boundary only), tubing, fittings, and bolting (mechanical closures). The applicant identified additional pipe/fittings and valves of the sampling system as subject to an AMR in its September 26, 2002, response to RAI 2.1-1 (discussed in Section 2.1 of this SER). The intended function for sampling components subject to an AMR is pressure boundary.

2.3.3.12.2 Staff Evaluation

The staff reviewed Section 2.3.3.12 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the sampling system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-12 of the LRA to determine whether the applicant appropriately identified the components of the sampling system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the sampling system that were not listed in Table 3.3-12 to verify with reasonable assurance that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 9.3.2 of the Unit 1 UFSAR and Section 9.3.2 of the Unit 2 UFSAR and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were not identified in Section 2.3.3.12 of the LRA.

The staff requested that the applicant clarify several items regarding the sampling system as detailed in the July 31, 2002, summary of the June 10—11, 2002, meeting. The staff questioned whether samples are taken directly from the low-pressure SI pump discharge header or from the minflow sample points during the recirculation period following a LOCA. The applicant clarified that the sample lines from the low-pressure SI pump perform no safety-related functions and are not credited as part of the post-accident sampling system. The staff finds the applicant's response acceptable on the basis that the applicant properly identified the minflow sample points as the components of the sampling system that perform an intended function. They are therefore within the scope of license renewal and subject to an AMR.

The staff also questioned the applicant about whether piping to the containment drain header, shown on license renewal boundary drawings 1-SI-02 at location A2 and 2-SI-02 at location A7, should be within the scope of license renewal, since it appears that the piping penetrates the containment wall in order to reach the containment drain tanks. The applicant stated that the portions of the reactor drain system that penetrate the containment wall are within the scope of license renewal and that the information is contained on license renewal boundary drawings 1-WM-01and 2-WM-01 for the waste management system. The staff finds the applicant's response acceptable on the basis that the components that perform an intended function are within the scope of license renewal and subject to an AMR.

The staff's review found that the components of the sampling system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.12.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the sampling system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Service Water (Potable and Sanitary Water)

2.3.3.13.1 Summary of Technical Information in the Application

In Section 2.3.3.13 of the LRA, the applicant identifies the components of the service water system that are within the scope of license renewal and subject to an AMR. The service water systems for Unit 1 and Unit 2 are described in Section 9.2.6, "Potable and Sanitary Water System," of the Unit 1 UFSAR and in Section 9.2.4, "Service and Potable Water System," of the Unit 2 UFSAR. The service water system is a common-site service for both St. Lucie Units 1 and 2.

The service water system, which is a non safety-related system and serves no safety function, is not required to achieve safe plant shutdown or to mitigate any accidents. The service water system supplies city water to the FP systems, the potable water system, washdown stations, and decontamination facilities. The service water system consists of two pumps, a hydropneumatic tank, and associated piping and valves. In addition, for Unit 2, failure of this system within the battery room in the RAB could result in the failure of safety systems to perform their intended function.

The service water system is within the scope of license renewal because it contains SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or systems, or SCs that are relied upon during fire events.

In Table 3.3-13 of the LRA, the applicant listed the service water system component types subject to an AMR as pumps and valves (pressure boundary only), piping, and fittings. The applicant also included the hydropneumatic tank, the domestic water pumps, and associated pipe/fittings and valves of the service water system as subject to an AMR in its November 27, 2002, supplemental response to RAI 2.3.3-15 (discussed in Section 2.3.3.6 of this SER). The intended function for service water components subject to an AMR is pressure boundary.

2.3.3.13.2 Staff Evaluation

The staff reviewed Section 2.3.3.13 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the service water system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-13 of the LRA to determine whether the applicant appropriately identified the components of the service water system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the service water system that were not listed in Table 3.3-13 of the LRA to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 9.2.6 of the Unit 1 UFSAR and Section 9.2.4 of the Unit 2 UFSAR to identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.13 of the LRA.

The staff's review found that the components of the service water system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.13.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the service water system components subject to an AMR in accordance with requirements stated in 10 CFR 54.21(a)(1).

2.3.3.14 Turbine Cooling Water (Unit 1 only)

2.3.3.14.1 Summary of Technical Information in the Application

In Section 2.3.3.14 of the LRA, the applicant identifies the components of the Unit 1 turbine cooling water system that are within the scope of license renewal and subject to an AMR. The turbine cooling water system is described in Section 9.2.4 of the Unit 1 UFSAR. The SBO function of the instrument air compressors cooled by the turbine cooling water system is described in the response to RAI 2.3.3-14.

The turbine cooling water system is a closed-loop system used to remove heat from the turbine and other components in the power cycle. A portion of the Unit 1 turbine cooling water system has the intended function of providing a cooling source for instrument air compressors 1A and 1B, which are credited for SBO events. The Unit 2 instrument air compressors are not credited during SBO events.

The applicant stated that some license renewal boundaries of the turbine cooling water system were established at normally open valves. The applicant considered this approach acceptable for the turbine cooling water system because the portion of Unit 1 turbine cooling water system that is required for SBO events must be manually isolated, in accordance with plant procedures, to accomplish its SBO function. Therefore, when the system is actually performing its required SBO function, there are no normally open valves at license renewal boundaries.

The Unit 1 turbine cooling water system is in the scope of license renewal because it contains structures or components that are relied on during SBO events.

In Table 3.3-14 of the LRA, the applicant identified the components of the turbine cooling water system that are subject to an AMR as pump and valves (pressure boundary only), tank, cooler, sight glasses, thermowells, piping, and fittings. The intended functions for turbine cooling water components subject to an AMR include pressure boundary and heat transfer.

2.3.3.14.2 Staff Evaluation

The staff reviewed Section 2.3.3.14 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the Unit 1 turbine cooling water system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-14 of the LRA to determine whether the applicant appropriately identified the components of the Unit 1 turbine cooling water system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the turbine cooling water system for Units 1 and 2 that were not listed in Table 3.3-14 to verify that the applicant appropriately identified the components that meet the above requirements. The staff also reviewed Sections 8.3, 9.2.4, and 15.2.13 of the Unit 1 UFSAR, and relevant sections of the UFSAR for Unit 2, and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.14 of the LRA.

During the review, the staff questioned the applicant's omission from Table 3.3-14 of certain passive and long-lived components in the instrument air system, which form the pressure boundary for the turbine cooling water system. By letter dated July 1, 2002, the staff requested that the applicant justify the exclusion of the following components from the scope of license renewal and being subject to an AMR.

- 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 on license renewal boundary drawing 1-TCW-01, at location B4

- instrument air compressors 1A and 1B shown on license renewal boundary drawing 1-TCW-01, at locations B4 and D4

If these components were included in Table 3.3-14 of the LRA under the "piping/fittings" component group, the staff requested that the applicant clarify why Table 3.3-14 does not list heat transfer as an intended function for these components.

The applicant responded to this RAI by letter dated October 3, 2002. In its response, the applicant stated that the instrument air compressor aftercoolers are addressed as a part of instrument air and listed in Table 3.3-8 of the LRA (pages 3.3-51, 3.3-52, and 3.3-56). The tube side ("instrument air compressor cooler tubes" component group on page 3.3-51) includes both heat transfer and pressure boundary as intended functions. The applicant considered instrument air compressors 1A and 1B within the scope of license renewal but not subject to an AMR because they are designated active components, in accordance with the requirements of 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. Instrument air and service air jacket coolers were also placed within the scope of license renewal but were not subject to an AMR. The applicant concluded that these coolers are an integral part of the air compressors and are, therefore, considered active components, in accordance with the requirements of 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10.

The applicant also responded that the service air compressor aftercooler was inadvertently omitted from Table 3.3-14 of the LRA. The aftercooler for service air has no heat transfer requirements but does perform a function of pressure boundary for turbine cooling water. In its response, the applicant revised Table 3.3-14 to include the service air aftercoolers.

The staff finds the applicant's response with regard to the service air compressor aftercoolers to be acceptable because it clarifies that these components are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively. The staff also agrees that the instrument air compressor itself is considered an active component in accordance with the requirements of 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10.

However, the staff questioned the applicant's conclusion that the instrument air and service air jacket coolers should be considered an integral part of the active instrument air compressor. Given the similarity to valve bodies and pump housings, it appeared that a leak in the water-filled jacket housing could cause a jacket cooler to fail its heat transfer and pressure boundary intended functions. The staff therefore requested that the NRC inspection team verify that the Unit 1 air compressor jacket coolers are integral parts of the instrument air compressors during an onsite scoping and screening audit conducted October 21 through 25, 2002.

As documented in the inspection report dated November 27, 2002, the water-filled jacket cooler (as noted above) consists of concentric cylinders around a piston cylinder. The cooling water enters the water jacket at the top of the cylinders and exits at the bottom. Plant inspection procedures require inspection for the accumulations of foreign matter or scale formations on the water jackets and water intakes. The NRC inspection verified that the cooling water jackets are an internal part of the compressors and are inspected during preventive maintenance of the compressors. On the basis of the inspection report cited above, the staff finds the applicant's conclusion that the jacket coolers are an integral part of the active instrument air compressor to be acceptable, and therefore, concludes that these jacket coolers are not subject to an AMR.

Also, by letter dated July 1, 2002, the staff requested the applicant to clarify the intended support function of the Unit 1 turbine cooling water system that led to the determination that only the Unit 1 turbine cooling water system is within the scope of license renewal, and to confirm that the Unit 2 turbine cooling water system does not perform a similar intended function.

In its response dated October 3, 2002, the applicant stated that instrument air compressors 1A and 1B are credited during a Unit 1 SBO event because they can be manually loaded onto a vital bus (Sections 8.3 and 15.2.13 of the Unit 1 UFSAR). A portion of Unit 1 turbine cooling water provides the cooling water source for these compressors and thus is within the scope of license renewal. The Unit 2 instrument air compressors 2A and 2B are not required to address SBOs at either unit. Therefore, the Unit 2 turbine cooling water system is not required to perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff finds the clarification provided in the applicant's response to be acceptable because it agrees with the staff's general understanding of the SBO functions of the Unit 1 turbine cooling water and instrument air systems contained in the UFSAR, and it clarifies the design differences between the two units that led to the determination that the Unit 2 turbine cooling water system has no intended functions that meet the criteria of 10 CFR 54.4(a).

The staff's review found that the components of the Unit 1 turbine cooling water system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.3.3.14.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the Unit 1 turbine cooling water system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.15 Ventilation

2.3.3.15.1 Summary of Technical Information in the Application

In Section 2.3.3.15 of the LRA, the applicant identifies the components of the ventilation systems that are within the scope of license renewal and subject to an AMR. This system is generally described in Section 6.2.2.2.2 of the UFSARs for St. Lucie Units 1 and 2; additional UFSAR sections are cited as references for the specific ventilation subsystems identified below.

Ventilation systems supply HVAC to various buildings, rooms, and areas throughout Units 1 and 2. The ventilation system includes subsystems within the scope of license renewal, and in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) respectively. For both Units 1 and 2, these subsystems include control room air conditioning, emergency core cooling systems (ECCS) area ventilation, RAB electrical and battery room ventilation, RAB main supply and exhaust, and shield building ventilation. The fuel handling building ventilation and intake structure ventilation subsystems are within the scope of license renewal and subject to an AMR for Unit 2 only. The miscellaneous ventilation subsystems (separate systems to cool the Unit 1 computer room and hot shutdown panel) are subject to an AMR for Unit 1 only.

The ventilation subsystems within the scope of license renewal and subject to an AMR for Units 1 and 2 are different for several reasons.

- The fuel handling building ventilation system is not safety related in the current licensing basis for Unit 1 but is safety related at Unit 2. The fuel handling building ventilation system for Unit 2 is considered to be within the scope of license renewal and subject to an AMR because it is safety related. The Unit 1 fuel handling building ventilation system is not considered to be within the scope of license renewal. The offsite radiological consequences of the design-basis FHA system for Unit 1 is much less than the limits specified in 10 CFR 100, even with the assumption of a ground-level release; therefore, the Unit 1 fuel handling building ventilation system does not perform an intended function that meets the criteria of 10 CFR 54.4(a)(3).

- The design-basis missile criteria are different between Units 1 and 2. As a result, Unit 1 missile protection at the intake structure consists of steel barriers with openings which allow for natural circulation cooling. The intake structure for Unit 2 is a fully enclosed concrete structure to provide for missile protection. Therefore, a forced ventilation system was provided to cool the Unit 2 intake pumps.

- The miscellaneous ventilation systems do not exist for Unit 2; the intended functions performed by these systems at Unit 1 are performed by the RAB electrical equipment and battery room ventilation system at Unit 2. The RAB electrical equipment and battery room ventilation system for both units are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

The ventilation system is within the scope of license renewal because its subsystems include SCs that are safety related and are relied upon to remain functional during and following DBEs, part of the EQ Program, relied on during fire events, or relied on during SBO events (Unit 1 only).

The design and intended functions of each of these subsystems will be discussed individually in the remainder of this section of the SER.

Control Room Air Conditioning. The control room ventilation system (CRVS) has the intended functions of maintaining habitability, temperature, and humidity inside the main control rooms for Units 1 and 2. The following information regarding the control room air conditioning system is provided in Sections 9.4.1 and 6.4.1 of the UFSARs for Units 1 and 2.

Section 9.4.1 of the Unit 1 and 2 UFSARs lists control room air conditioning system design bases for both St. Lucie units. The Unit 1 control room air conditioning system design bases include the following objectives.

- limit control room doses due to airborne activity to within General Design Criterion (GDC) 19 limits
- maintain the ambient temperature required for personnel comfort during normal conditions
- permit personnel occupancy and proper functioning of I&C during all normal and LOCA conditions assuming a single active failure
- withstand design-basis earthquake loads without loss of function
- permit personnel occupancy during a toxic gas release accident

The Unit 2 control room air conditioning system design bases include the following objectives.

- control the environment in the control room envelope for the comfort of control room personnel and assure the operability of control components during normal plant operation, anticipated operational occurrences, or abnormal occurrences
- ensure that no single active failure coincident with a loss of offsite power can result in loss of functional performance
- maintain the control room envelope at an average positive pressure of 0.03 kPa (1/8 inch w.g.) above that of the surroundings during normal plant operation and following a LOCA.
- provide means to limit the introduction of airborne radioactivity, smoke, toxic gases, or steam to the control room envelope
- provide air cleaning for the control room envelope atmosphere so that airborne radiological doses experienced by control personnel following a design-basis accident (DBA) do not exceed limits imposed by GDC 19
- ensure that makeup air brought in during an event that has resulted in control room isolation does not bypass the air cleaning process before it mixes with the control room envelope air

- ensure that essential portions of the systems and control components are protected against missiles (internal and external) and floods and are designed to remain functional subsequent to a safe shutdown earthquake

- provide accessibility for adjustments, periodic inspections, and testing of the system components to ensure continuous functional reliability

During normal operation, this system draws air from its associated control room, passes the air through air conditioning units, and returns the air to the control room. In addition, outside makeup air is supplied to ensure that a positive pressure is maintained in the control room.

During emergency conditions, outside air is isolated, and the control room air is recirculated. A portion of the recirculated control room air is passed through high-efficiency particulate air (HEPA) filters and charcoal adsorbers. Emergency conditions are triggered by (1) receipt of a containment isolation signal (CIS), or (2) receipt of a high radiation alarm on the intake radiation monitors, or (3) loss of power to the intake radiation monitors.

The Unit 1 control room air conditioning system consists of three 50-percent capacity split-system air conditioning units (each having an indoor and outdoor section), a ducted air intake and air distribution system, and a filter train with HEPA filters and charcoal adsorbers with two redundant booster centrifugal fans. The indoor sections are located at elevation 62 feet and include a cabinet-type centrifugal fan, a direct expansion refrigerant cooling coil, and filters. Each of the three outdoor section units is a single assembly which includes a refrigerant condensing coil and fans and a refrigerant compressor, located on the roof of the adjoining Unit 1 RAB. During normal operation, two of the three air conditioning units are in operation, while the third unit is on standby status.

Control room air is drawn into the indoor air handling section through a return air duct system and roughing filters and is cooled as required. Conditioned air is directed back to the control room through a supply air duct system. Outside air makeup enters through either of two outside air intakes located in the north and south walls of the RAB.

The control room has three air duct penetrations (two for the outside air intake and one for the toilet area ventilation and kitchen exhausts). Upon receipt of a CIS from either Unit 1 or 2, or a high-radiation signal, the booster fans are automatically started and the charcoal filter train dampers are opened. Outside air intake is isolated by low-leakage redundant dampers located in the outside air makeup ducts. The outside air intake dampers also close upon receipt of a high radiation signal from radiation monitors located in the air intakes. Kitchen and toilet exhaust ducts are also isolated by low-leakage redundant dampers. The control room air is then recirculated through the HEPA filters and charcoal adsorbers.

During post-LOCA operation, the control room air conditioning system maintains a positive control room pressure. The control room filtration system has been modified to increase its dose reduction effectiveness during the post-LOCA operating mode. Flow control dampers installed in each air intake control the flow of air being drawn into the control room. Post-LOCA makeup flow enters through one of these dampers and passes through the charcoal filters. As a result, all makeup air is filtered. Upon loss of offsite power, the air conditioner units are automatically loaded on the EDGs.

The control room air conditioning system for Unit 2 differs from that of Unit 1, which uses a direct expansion refrigeration system to cool the air, with three 50-percent capacity refrigerant loops split between indoor and outdoor units. The Unit 2 air conditioners are cooled by the component cooling water system and are located entirely indoors.

In Table 3.3-15 of the LRA, the applicant identifies the component types of the control room air conditioning system that are subject to an AMR. The component types subject to an AMR identified for both St. Lucie units are valves, piping/fittings, tubing/fittings, thermowells, filter housings, ducts, orifices, flexible connections, and bolting (mechanical closures). The components identified as being applicable for Unit 2 only are control room air conditioner heat exchanger condenser shell, vents, drains, baffles, and support plates; control room air conditioner heat exchanger channel, vents, and drains; and control room air conditioner heat exchanger tubes and tubesheets.

In response to RAI 2.3.3.15-1 from the staff, the applicant revised Table 3.3-15 to add fan and damper housings. Sealant materials used to maintain the positive pressure of the main control room envelope are subject to an AMR as structural components in Tables 3.5-8 and 3.5-12 of the LRA. In Table 3.3-15 of the LRA, the applicant lists the intended functions of the control room air conditioning system components as pressure boundary, heat transfer, or throttling.

Emergency Core Cooling System Area Ventilation System. The ECCS area ventilation system has the post-LOCA intended function of filtration and adsorption of fission products in the exhaust air from areas of the RAB which contain containment isolation valves, high- and low-pressure SI pumps, containment spray pumps, shutdown heat exchangers, and piping which may contain recirculated containment sump water. These components require ventilation to operate properly. The ECCS area ventilation system is discussed as follows in Section 9.4.3 of the UFSARs for Unit 1 and 2.

Redundant safety-related components are served by separate ventilation trains. In this way, failure of a single active ventilation component can affect operation of only one of the redundant safety-related components. Each of the redundant ventilation components and its controls is powered from a separate emergency bus.

During normal operation, the RAB main ventilation supply and exhaust system provides the necessary ventilation of the ECCS pump rooms. Under accident conditions when several or all of the pumps are operating, the air supply to the nonessential section of the RAB is directed to the pump rooms to provide the additional cooling air requirement. Dampers are positioned automatically on a safety injection actuation signal (SIAS) to provide the proper flow path for supply air to the ECCS area. Simultaneously, the exhaust fans are energized and dampers in the exhaust ductwork are positioned to allow the fans to draw all exhaust air from the area through the HEPA and charcoal filter banks before discharge to the atmosphere. (The air exhaust system comprises two redundant trains, each having a centrifugal fan, a HEPA and charcoal filter bank, and associated ductwork, dampers and controls.) Two ECCS area ventilation system exhaust monitors, connected to the noble gas monitoring system, measure the airborne effluent from the ECCS area.

The system is sized to maintain a slightly negative pressure of between 0.06 - 0.25 kPa (0.25 to 1 inch w.g.) in the ECCS area with respect to surrounding areas of the RAB. Ductwork transporting air to the filter banks is also at negative pressure. Dampers connecting the ECCS area ventilation system with other parts of the auxiliary building main exhaust and supply systems fail in the closed position upon loss of control air or power. Dampers, which align flow from the area through the charcoal filter train and exhaust fans, fail in the open position.

The applicant lists the component types of the ECCS area ventilation system that are within the scope of license renewal and subject to an AMR in Table 3.3-15 of the LRA. Specifically, the component types include valves, tubing/fittings, thermowells, filter housings, ducts, orifices, flexible connections, and bolting (mechanical enclosures). In response to RAI 2.3.3.15-1 from the staff, the applicant revised Table 3.3-15 to add fan and damper housings. In Table 3.3-15 of the LRA, the applicant lists the intended functions of these items as pressure boundary and throttling.

Fuel Handling Building Ventilation System (Unit 2 Only). The Unit 2 fuel handling building ventilation system has the intended function of preventing the buildup of airborne radioactivity in the fuel handling building and providing ventilation to fuel pool cooling equipment located in the building. As discussed above, only the Unit 2 fuel handling building ventilation system is within the scope of license renewal and subject to an AMR. More detailed information pertaining to the fuel handling building ventilation systems is provided as follows in Section 9.4.6 of the Unit 1 UFSAR and in Section 9.4.2 of the Unit 2 UFSAR. As stated in the Unit 2 UFSAR, the design bases for the fuel handling building ventilation have the following objectives.

- direct airflow from areas of low potential radioactivity to areas of progressively higher potential radioactivity and prevent accumulation of airborne radioactivity in the fuel handling building
- maintain a negative pressure with respect to outside area when all outside doors are closed
- limit offsite effluents from the fuel pool area during normal operation by removing airborne radioactive particulates through HEPA filtration
- via the bypass through the shield building ventilation system (SBVS), limit the offsite exposures resulting from an FHA to within the limits of 10 CFR 100, assuming a single active failure

During normal operation, the fuel handling building is ventilated by two supply air systems. Each supply system consists of a hooded wall intake and air handling unit with roughing filters, fan section, and a duct distribution system. One system supplies air to the fuel pool area including the fuel storage area, while the other system supplies air to the balance of the fuel handling building, excluding the HVAC equipment room. The HVAC equipment room is ventilated by a separate exhaust fan. Air exhaust from the fuel handling building equipment area is passed through a prefilter and HEPA filter bank before being discharged by a centrifugal fan to the atmosphere via the fuel handling building vent stack.

The portion of the fuel handling building ventilation system used for SFP ventilation is interconnected with the SBVS. Upon receipt of a high-radiation signal from the fuel pool area, the redundant fail closed isolation dampers located at the fuel pool area supply and exhaust penetrations automatically close, and the supply and exhaust fans used for fuel handling building ventilation under normal operation are de-energized. The normally closed isolation valves in the interconnecting line to the SBVS then open. The fans in the SBVS automatically start and evacuate air from the fuel pool area through the interconnecting line. This air is then passed through the SBVS charcoal and HEPA filters before being discharged through the plant vent stack. Evacuation of the fuel pool area air by the SBVS ensures a negative pressure in that area to preclude unfiltered leakage of radioactivity to the environment.

Although Section 2.3.3.15 of the LRA does not describe the fuel handling building ventilation system for Unit 1, the description provided in Section 9.4.6 of the Unit 1 UFSAR is similar to that of Unit 2, except for the interconnecting line to the SBVS.

In Table 3.3-15 of the LRA, the applicant listed the component types of the Unit 2 fuel handling building ventilation system that are within the scope of license renewal and subject to an AMR. Specifically, the component types include valves, tubing/fittings, ducts, flexible connections, and bolting (mechanical enclosures). In response to RAI 2.3.3.15-1 from the staff (discussed below), the applicant revised Table 3.3-15 to add damper housings. The intended function of the fuel handling building ventilation system components listed in Table 3.3-15 is pressure boundary.

Intake Structure Ventilation (Unit 2 Only). The intake structure ventilation system for Unit 2 has the intended function of cooling the safety-related intake pumps, located in the enclosed St. Lucie Unit 2 intake structure. Portions of the Unit 1 intake structure are open to the weather, and the structure does not require a forced ventilation system. More detailed information pertaining to the intake structure ventilation system is provided as follows in Section 9.4.6 of the Unit 2 UFSAR.

The Unit 2 intake structure ventilation system consists of two redundant 100-percent capacity propeller exhaust fans, two pressure dampers, and two screened openings. The air drawn through the screened openings is exhausted by the fans to the atmosphere. Normally, one of the fans is operated, as necessary, to maintain the temperature of the ICW pump room at less than 49 °C (120 °F). Missile protection and pressure dampers are provided in the exhaust opening to protect the exhaust fans from external missiles and excessive wind conditions.

Although the applicant categorized this system as within the scope of license renewal, all of the components of this system shown as within the scope of license renewal (on license renewal boundary drawing 2-HVAC-1 at location F5) are either considered active, in accordance with 10 CFR 50.21(a) and the guidance given in NEI 95-10, or do not have an intended function that meets the scoping criteria of 10 CFR 54.4(a). Therefore, the Unit 2 intake structure ventilation system does not have any components listed in Table 3.3-15 that are within the scope of license renewal and subject to an AMR.

Miscellaneous Ventilation (Unit 1 Only). As defined in Section 2.3.3.15 of the LRA, the miscellaneous ventilation systems provide ventilation for the Unit 1 computer room and hot shutdown panel room. These systems are not described in the Unit 1 UFSAR; however, the components of the miscellaneous ventilation systems are shown in license renewal boundary diagrams 1-HVAC-01 and 1-HVAC-02. The Unit 2 RAB electrical equipment and battery room ventilation system provides ventilation for the Unit 2 hot shutdown panel and computer rooms.

Should an emergency condition cause the control room to be abandoned, local emergency I&C are provided at the hot shutdown panel to enable the operator to maintain the unit at hot shutdown conditions from outside the control room. Section 7.4.1.8 of the Unit 1 UFSAR provides further information concerning the hot shutdown panel but does not discuss cooling of the hot shutdown panel room. As shown on license renewal boundary drawing 1-HVAC-01, the

Unit 1 hot shutdown panel room is ventilated by a system consisting of an outside air intake, a supply fan (HVS-9) and prefilters packaged in a single housing, a motor-operated damper upstream of the fan unit, an exhaust fan (HVE-35) mounted in the wall and exhausting to the atmosphere, and associated ductwork.

As shown in license renewal boundary drawing 1-HVAC-02, the Unit 1 computer room is ventilated by supply air consisting of air recirculated back from the computer room, mixed with air diverted from the technical support center supply air (which is supplied by the CRVS). Redundant supply fan units HVA-10A and B (shown on drawing 1-HVAC-02 at locations C8 and D8), each consisting of a fan and prefilters packaged in a single housing, provide air to the computer room. Motor-operated dampers are located upstream and downstream of each fan unit. The computer room ventilation system is entirely within the control room envelope.

The applicant listed the Unit 1 component types of the miscellaneous ventilation systems that are within the scope of license renewal and subject to an AMR in Table 3.3-15. Specifically, the component types include filter housings, flexible connections, ducts, and bolting (mechanical enclosures). In response to RAI 2.3.3.15-1 from the staff (discussed below), the applicant revised Table 3.3-15 to add damper housings. The intended function of these components listed in Table 3.3-15 is pressure boundary.

<u>RAB Electrical and Battery Room Ventilation System</u>. The Units 1 and 2 RAB electrical and battery room ventilation systems are safety related since they are required for proper functioning of the emergency electrical distribution equipment. More detailed information regarding these systems is provided as follows in Sections 9.4.2.2.2 of the Unit 1 UFSAR and Section 9.4.3.2.2 of the Unit 2 UFSAR.

For Unit 1, electrical equipment rooms 1A, 1B, and 1C, the static inverter room, and battery rooms 1A and 1B are ventilated by an air supply subsystem and individual room exhaust fans. Air is supplied through a louvered intake, filters, two centrifugal supply fans operating in parallel, and a duct distribution system. Equipment room 1A is exhausted by two power roof ventilators, while equipment rooms 1B and 1C and the static inverter room are exhausted through wall fans. Equipment room 1C is also provided with supplemental cooling from two non safety-related air conditioning units. Battery rooms 1A and 1B are exhausted by power roof ventilators. All of these components are operating under normal conditions.

Upon loss of offsite power, the electrical equipment room supply fans and the battery room exhaust fans are automatically connected to the EDGs. The electrical equipment room exhaust fans are manually restarted by administrative control and are powered by separate emergency busses, as are the battery room exhaust fans. The supply fans are similarly powered by separate busses.

During normal operation, with one non-safety-grade air conditioner and all supply and exhaust fans operating, the ventilator air flow rates for the electrical equipment rooms, static inverter room, and battery rooms are selected to maintain a temperature of less than 40 °C (104 °F), with the outside air temperature at 34 °C (93 °F). In the event both air conditioners are not in operation, the ventilator air flow rates are sufficient to maintain all the rooms at less than 40 °C (104 °F). With one supply fan and one air conditioner operating, the supply fan operates at two-thirds the capacity of two supply fans, sufficient to maintain all rooms below 40 °C (104 °F).

During an emergency condition that involves a loss of offsite power, the automatic restart of the battery room exhaust fans and the electrical equipment room supply fans ensures that temperatures will not exceed 49 °C (120 °F) in any of the rooms.

Unit 2 differs from Unit 1 in several ways. First, upon loss of offsite power, the entire system is automatically connected to the EDGs, unlike Unit 1 where the electrical equipment room exhaust fans are manually restarted. Second, ventilator air flow rates for the electrical equipment, static inverter, and battery rooms are selected to maintain a temperature of less than 43 °C (110 °F), with an outside air temperature of 34 °C (93 °F). Third, the Unit 2 hot shutdown cubicle is cooled by the RAB electrical and battery room ventilation systems, while the Unit 1 hot shutdown panel room is cooled by a portion of the Unit 1 miscellaneous ventilation system.

The applicant identified the component types that are within the scope of license renewal and subject to an AMR in Table 3.3-15 of the LRA. Specifically, the component types include shell for HVS-5A and B plenum and filters (Unit 1 only), internal structural supports for HVS-5A and B plenum and fans, filter holding frames, ducts, flexible connections, thermowells, tubing/fittings, and bolting (mechanical enclosures). In response to RAI 2.3.3.15-1 from the staff (discussed below), the applicant revised Table 3.3-15 to add fan and damper housings. The intended function of these items is also listed in Table 3.3-15 as pressure boundary and structural support.

<u>RAB Main Supply and Exhaust System</u>. The RAB main supply and exhaust system performs the intended function of supplying air to the ECCS pump rooms, shutdown cooling heat exchanger rooms, penetration areas, and nonessential areas of the RAB. The RAB main supply and exhaust system is discussed as follows in Sections 9.4.2.2.1 and 9.4.3.2.1 of the UFSARs for St. Lucie Units 1 and 2, respectively.

The RAB main supply and exhaust system consists of a redundant air supply system and a redundant air exhaust system. The air supply flows through wall louvers, roughing filters, two 100-percent capacity centrifugal fans, and associated duct distribution systems. Under loss of normal power, the supply fans are automatically connected to the EDG set, and each fan is powered from a separate bus. The air exhaust system includes a 100-percent capacity bank of prefilters and HEPA filters, two 100-percent capacity exhaust fans, and duct exhaust systems. Exhaust air is discharged through the plant vent stack.

Under normal operation, the RAB main supply and exhaust system provides the necessary ventilation of the ECCS pump rooms. Under accident conditions when several or all of the ECCS pumps are operating, the air supply to the nonessential section of the RAB is directed to the pump rooms to provide additional cooling. Dampers are positioned automatically to provide the proper flow path for supply air to the ECCS area. Simultaneously, the ECCS area ventilation system exhaust fans are automatically energized, and dampers in the exhaust ductwork of that system are automatically positioned to allow the fans to draw all exhaust air from the areas through the HEPA and charcoal filter bank before discharge to the atmosphere. (The ECCS area ventilation system is discussed above.) Under accident conditions, the air from the ECCS pump rooms is exhausted by the ECCS area ventilation system and not the RAB main supply and exhaust system; therefore, the exhaust portion of the latter system is not safety related.

The applicant lists the component types of the RAB main supply and exhaust system that are within the scope of license renewal and subject to an AMR in Table 3.3-15 of the LRA. Specifically, the component types include shell (housing) for HVS-4A and 4B plenum and filters, internal structural supports for HVS-4A and 4B plenum and fans, filter holding frames, ducts, flexible connections, thermowells, tubing/fittings, and bolting (mechanical closures). In response to RAI 2.3.3.15-1 from the staff (discussed below), the applicant revised Table 3.3-15 to add fan and damper housings. The intended functions of the RAB main supply and exhaust system components listed in Table 3.3-15 are pressure boundary and structural support.

Shield Building Ventilation System. The SBVS has the intended functions of (1) limiting the pressure rise in the shield building annulus following a LOCA so as not to exceed the shield building internal design pressure, (2) maintaining a small subatmospheric pressure in the shield building annulus of each unit following a LOCA to ensure that offsite doses resulting from post-accident leakage from the containment are reduced by routing the air through the shield building filters, and (3) providing fission product removal capacity to reduce the offsite doses resulting from post-accident leakage from the containment. The SBVS is discussed as follows in Section 6.2.3 of the UFSARs for St. Lucie Units 1 and 2.

The SBVS consists of two full-capacity redundant fan and filter subsystems which share a common shield building duct intake and a common plant vent. Each filter subsystem consists of demisters, electric heating coils, and HEPA filters and charcoal adsorbers enclosed in a common casing. The annulus air intake consists of a ring duct with inlets at approximately elevation 62 feet located at each quadrant and at the top of the shield building. Two separate 76-cm (30-inch) diameter lines from the ring duct penetrate the shield building walls to connect to their corresponding filter subsystems. The fan and filter subsystems are located in the RAB. Outside air lines, 168 cm^2 (26 in^2), each isolated by a check valve and a motor-operated valve in series, are connected to the intake of the filter subsystems to provide cooling air to the filters when required. A 30.5-cm (12-inch) line with an isolating butterfly valve cross-connects the filter subsystems downstream of the filter banks and upstream of the fans to maintain flow through the filters in the event of failure of a fan. A gravity damper is located at the discharge of each fan to prevent loss of capacity of an operating fan due to recirculation through an inactive system.

After a LOCA, the temperature expansion of the containment vessel and the heat transfer through the vessel walls to the annulus result in a decrease in the shield building volume and an increase in annulus pressure. This pressure increase is rapidly drawn down by operation of the SBVS. The motorized dampers downstream of the fans are normally open. Upon receipt of a containment isolation actuation signal, the fans are in full operation in 10 seconds, assuming offsite power is available. Upon a coincident loss of offsite power, the fans receive a start signal but are not actuated until they are loaded onto the DGs. Once started, the fan exhaust rate reduces as drawdown to negative pressure proceeds. The fan continues exhausting air at a decreasing rate, until the pressure in the shield building is 0.5 kPa (2 inch w.g.) negative with respect to atmospheric, as sensed by a pressure differential transmitter. At this point, a motorized damper at the discharge of the fan closes to a pre-set position to throttle air flow to the continuous rated system flow of 2.8 m^3/s (6000 cfm). As the shield building annulus becomes evacuated and the heat transfer rate from the containment stabilizes, the amount of outflow from the annulus is essentially balanced by shield building in-leakage.

The Unit 1 SBVS is interconnected to the hydrogen purge system. The Unit 2 SBVS is similarly interconnected to the continuous containment/hydrogen purge system.

The applicant listed the component types of the SBVS that are within the scope of license renewal and subject to an AMR in Table 3.3-15 of the LRA. Specifically, the component types include valves, tubing/fittings, thermowells, piping, filter housings, demisters, flexible connections, ducts, and bolting (mechanical closures). In response to RAI 2.3.3.15-1 from the staff (discussed below), the applicant revised Table 3.3-15 to add fan and damper housings. The intended functions of the SBVS components listed in Table 3.3-15 are pressure boundary and moisture removal.

2.3.3.15.2 Staff Evaluation

The staff reviewed Section 2.3.3.15 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant adequately identified the components of the ventilation system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-15 of the LRA to determine whether the applicant adequately identified the components belonging to the ventilation system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the ventilation system that were not listed in Table 3.3-15 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 6.2.2.2.2 and other relevant sections of the Unit 1 and 2 UFSARs and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.15 of the applicant's LRA.

After the staff's initial review, certain issues common to all of the ventilation subsystems were identified and grouped into three general RAIs. These issues pertain to fan and damper housings, filter media, and other components that the applicant did not identify as being subject to an AMR. The license renewal boundary drawings supplied by the applicant for the ventilation systems show various dampers and fans as being within the scope of license renewal. However, Table 3.3-15 of the LRA does not include the housings for the dampers and fans. By letter dated June 18, 2002, the staff requested that the applicant either include these housings in Table 3.3-15 or justify their omission (RAI 2.3.3.15-1). This RAI identifies 172 fan and damper housings and the corresponding license renewal boundary drawing locations where they are shown.

By letter dated October 3, 2002, the applicant responded that, based on the staff's position on previous LRA, as well as staff expectations expressed at prior meetings, fan and damper housings have now been included as subject to an AMR for applicable ventilation systems. Revised versions of Table 3.3-15 with appropriate additions were provided for several subsystems with fan and/or damper housings. These include control room air conditioning, ECCS area ventilation, Unit 2 fuel handling building ventilation, Unit 1 miscellaneous ventilation, RAB electrical and battery room ventilation, RAB main supply and exhaust, and shield building ventilation.

The staff considers the applicant's response to RAI 2.3.3.15-1 acceptable on the basis that the applicant has included the fan and damper housings for the applicable ventilation subsystems as within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

The license renewal boundary drawings provided by the applicant for ventilation subsystems show various system filters as being within the scope of license renewal. However, Table 3.3-15 of the LRA does not identify the filter media as subject to an AMR nor does it provide a justification for their exclusion. System filters are passive and may be long-lived and, as such, are within the scope of license renewal and subject to an AMR. Media for system filters may be excluded from being subject to an AMR if they are replaced periodically or routinely replaced dependent on condition. In such cases, the applicant should specify the basis for the exclusion of filter media and describe the plant-specific monitoring program and the performance standards and criteria for replacement. In a letter dated July 18, 2000, the staff requested that the applicant justify the omission of the filter media (RAI 2.3.3.15-2). The RAI identifies 33 system filters and the corresponding license renewal boundary drawing locations where they are shown.

By letter dated October 3, 2002, the applicant identified those filters where media are replaced periodically in accordance with plant procedures at intervals ranging from monthly to every 13 weeks. Also identified were HEPA and charcoal filters where media are tested and replaced in accordance with the St. Lucie technical specifications that define specific performance standards and criteria. The applicant identified the specific technical specifications in the response.

The staff considers the applicant's response to this RAI acceptable on the basis that the filter media identified in the RAI are either replaced periodically (with replacement intervals specified) or routinely replaced on their condition, in accordance with technical specifications which define specific performance standards and criteria. Therefore, all of the filter media identified in RAI 2.3.3.15-2 are excluded from being subject to an AMR in accordance with 10CFR 54.21(a)(1)(ii).

The license renewal boundary drawings provided by the applicant for the ventilation subsystems show the following components as being within the scope of license renewal but not listed in Table 3.3-15 as being subject to an AMR.

- intake screen for hot shutdown panel ventilation outside air inlet (Unit 1)
- direct expansion cooling coils and coil housings located in the CRVS (Units 1 and 2)
- electrical heating coils and housings located in the SBVS (Units 1 and 2)
- demister housings located in the SBVS (Units 1 and 2)
- screened openings and associated intake structure ductwork (Unit 2)

In a letter dated July 18, 2002, the staff requested that the applicant justify the omission of these components from Table 3.3-15 (RAI 2.3.3.15-3). The applicant's response to this RAI will be addressed in the following staff evaluations of the individual ventilation subsystems in which these components are located.

<u>Control Room Ventilation System Staff Evaluation</u>. After completing the initial review of the CRVS, in a letter dated July 18, 2002, the staff requested that the applicant describe the main control room environment (MCRE) for Units 1 and 2 and verify that all CRVS components that are relied upon to perform a safety-related function, and are passive and long-lived, are

identified in the LRA as being within the scope of license renewal and subject to an AMR (RAI 2.3.3.15-5).

By letter dated October 3, 2002, the applicant responded by identifying the areas which are included in the MCRE for Units 1 and 2. In addition, the applicant stated that all Unit 1 and Unit 2 control room air conditioning components are safety related and within the scope of license renewal with the exception of the toilet and kitchen exhaust fans that are isolated under emergency conditions. Those components which are passive and long-lived are subject to an AMR and are listed in Table 3.3-15, as amended by the responses to RAIs 2.3.3.15-1 and 2 discussed earlier.

The staff considers the applicant's response to RAI 2.3.3.15-5 to be acceptable on the basis that the applicant has defined the MCRE for both Units 1 and 2 and has included in Table 3.3-15, as verified by the staff, all components of the control room air conditioning system that are within the scope of license renewal and are subject to an AMR.

The staff review identified several components that are highlighted as being within the scope of license renewal on the license renewal boundary drawings but are not listed in Table 3.3-15. These include the Unit 1 direct expansion cooling coils and coil housings for indoor HVAC Units HVA-3A, 3B, and 3C, and the Unit 2 direct expansion cooling coils and coil housings for HVAC Units 2HVA/ACC-3A, B, and C. In a letter dated July 18, 2002, the staff requested that the applicant justify the omission of these components from Table 3.3-15 (RAI 2.3.3.15-3).

The staff's review also found that license renewal boundary drawing 1-HVAC-02 (for Unit 1) and Table 3.3-15 do not identify several components as being within the scope of license renewal. These include the piping, valves, and flexible connections in the refrigerant lines to and from the outdoor air conditioner compressor units, ACC-3A, ACC-3B, and ACC-3C, to the corresponding indoor air conditioner units, HVAC-3A, HVAC-3B, and HVAC-3C (locations A7, B7, C7). These components should be within scope because they support the intended function of the CRVS to comply with the requirements of GDC 19. In a letter dated July 18, 2002, the staff requested that the applicant provide justification as to why these components are considered outside the scope of license renewal and not subject to an AMR (RAI 2.3.3.15-7).

By letter dated October 3, 2002, the applicant responded to RAIs 2.3.3.15-3 and 2.3.3.15.7 by stating that FPL's screening methodology treats components that are associated with the refrigeration process (such as the above-mentioned components) as active components that are, therefore, not subject to an AMR. The applicant also stated that this conclusion is consistent with that accepted by the staff as part of the Turkey Point Units 3 and 4 LRA review. The applicant's conclusion is based on the rationale that direct expansion refrigeration units (packaged or split) typically consist of refrigerant compressors, condensers, evaporators, expansion valves, economizers and copper tubing, compressor motors, condenser fan motors, and controls. These components are linked together by interconnecting piping, forming the refrigerant circuit. Deteriorating conditions in any of these components will cause the units to either trip or noticeably subperform. Thus, any detrimental effect of aging mechanisms on the refrigerant circuit components is translated to a change in the monitored operational performance of the units. Typically, condensing units are replaced as an integral unit in lieu of individual component repairs. Operability of these refrigeration units is addressed in the St. Lucie technical specifications. On this basis, the applicant considers all the components in the refrigerant loop as active.

As part of its consideration of the applicant's response to the RAIs 2.3.3.15-3 and 2.3.3.15-7, the staff requested that the inspection team confirm that the control room air conditioning system direct expansion refrigerant loops are maintained as a single integral unit during the site scoping and screening audit held October 21 through 25, 2002. As documented in Inspection Report 2002-07, dated November 27, 2002, the inspector reviewed maintenance records (PCM021-195) for the Unit 1 main control room air conditioning system direct expansion refrigerant cooling units associated with air handling units HVAC-3A, 3B, and 3C, including components located outdoors (ACC-3A, 3B, and 3C) and verified that the components in the refrigerant loop are replaced together. The inspector also reviewed the St. Lucie Unit 1 electrical maintenance procedure for the preventive maintenance of the control room air conditioning units HVA/ACC 3A, 3B, and 3C (1-EMP-25.08) and verified that the components in the refrigerant loop are serviced together, whenever any of the components in the loop are serviced.

With regard to RAI 2.3.3.15-7 and the applicable portion of RAI 2.3.3.15-3, the staff finds the applicant's conclusion to be acceptable; the components in the Unit 1 control room air conditioning refrigeration loops can be considered active on the basis that (1) these units are subject to performance monitoring and their operability is addressed in the technical specifications, (2) a deteriorating condition in any of these components resulting from aging would cause the unit to trip or cause degraded performance, at which point repair or replacement would be effected, and (3) as verified during the scoping and screening inspection, the components in the refrigerant loops are treated as an integral unit and are serviced together whenever any of the components in the loop are serviced.

ECCS Area Ventilation Staff Evaluation. The staff's review of the ECCS area ventilation and other systems indicated that many symbols used for HVAC system components in the license renewal boundary drawings were not defined on the "General Notes and Legend," Drawings 1-NOTES-1 and 2-NOTES-1. For the ECCS area ventilation system in particular, the components downstream of exhaust fans HVE-9A and B (drawing 1-HVAC-02, locations D-5 and E-5) could not be identified. By letter dated July 18, 2002, the staff requested that the applicant identify the subject components (RAI 2.3.3.15-4).

By letter dated October 3, 2002, the applicant responded that the components referred to in the RAI are flow monitors and isokinetic sampling devices. The applicant further stated that these components do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10CFR 54.4(a).

The staff considers the applicant's response to be acceptable on the basis that these components do not perform any license renewal system intended function and that failure of these components would not prevent or impair the ECCS area ventilation system from performing its intended function in accordance with 10 CFR 54.4(a)(2).

Fuel Handling Building Ventilation Staff Evaluation (Unit 2 only). After completing the initial review of the Unit 2 fuel handling building ventilation system, the staff reviewed the basis for exclusion of the Unit 1 fuel handling building ventilation system. Section 9.4.2 of the Unit 1 UFSAR states that the offsite doses resulting from an analysis of the FHA (as shown in Table 15.4.1-5 of the UFSAR) are considered acceptably low. The consequences of an FHA are much less than the limits specified in 10 CFR 100, even with the assumption of a ground-level release. In addition, as discussed in Section 9.4.6 of the UFSAR for St. Lucie Unit 1, the staff required that a single charcoal bed filter downstream of the HEPA filters in the fuel pool exhaust area be installed. This modification was completed before the initial transfer of spent fuel from the Unit 1 containment. The purpose of this filter is to remove elemental iodine.

Because the charcoal filter, as well as the rest of the fuel handling building ventilation system for Unit 1, was not considered to be within the scope of license renewal in the LRA, the staff requested that the applicant provide justification as to why the SCs of the Unit 1 system are considered outside the scope of license renewal and not subject to an AMR by letter dated July 18, 2002 (RAI 2.3.3.15-8).

By letter dated October 3, 2002, the applicant responded that, as documented in Sections 9.4.6 and 15.4.1 of the Unit 1 UFSAR, the fuel handling ventilation system is not relied on nor credited in the safety analysis for FHAs. As such, the system does not perform or support any license renewal system intended functions that satisfy the scoping requirements of 10 CFR 54.4(a). Therefore, components of the Unit 1 fuel handling ventilation system are not within the scope of license renewal or subject to an AMR.

The staff considers the applicant's response to this RAI acceptable on the basis that the Unit 1 fuel handling building ventilation system and its components are not relied upon to limit the radiological release from an FHA to meet the requirements of 10 CFR 100 and thus do not perform an intended function that meets the criteria of 10 CFR 54.4(a)(1)(iii). In addition, none of the components of this system are relied upon to demonstrate compliance with NRC regulations for FP, EQ, PTS, ATWS, and SBO. As a result, the staff concurs with the applicant's position that the Unit 1 fuel handling building ventilation system and its components can be excluded from the scope of license renewal.

<u>Intake Structure Ventilation Staff Evaluation (Unit 2 Only)</u>. As discussed above, certain issues common to all of the ventilation subsystems were identified and grouped into three general RAIs. The issues pertaining to the omission of fan and damper housings from Table 3.3-15 applied, in part, to the intake structure ventilation system for Unit 2. On license renewal boundary drawing 2-HVAC-01, the housings for the intake structure exhaust fans, 2HVE-41A and 41B, are shown at location F5, and the housings for the unlabeled intake structure pressure dampers, are also shown at location F5. In a letter dated June 18, 2002, the staff requested that the applicant either include these housings in Table 3.3-15, or justify their omission (RAI 2.3.3.15-1).

By letter dated October 3, 2002, the applicant responded to RAI 2.3.3.15-1. In the portion of its response that pertains to the intake structure ventilation fan and damper housings, the applicant stated that the intake structure fans, 2HVE-41A and 2HVE-41B, are mounted in the roof of the ICW pump enclosure and thus do not have housings. Similarly, the intake structure ventilation dampers are mounted in the wall of the intake structure, and thus do not have housings.

The staff considers the applicant's response to the portion of RAI 2.3.3.15-1 that pertains to the intake structure ventilation system to be acceptable on the basis that these components do not have housings but are mounted directly on the intake structure. These structures are identified as within the scope of license renewal and subject to an AMR in Section 2.4.2.10 of the LRA.

During the course of the review, the staff observed that screened openings and associated intake structure ductwork (as identified in Section 9.4.6.2 of the Unit 2 UFSAR) were not listed in Table 3.3-15 as subject to an AMR. Since these components are passive, long-lived, and part of a safety-related system, the staff concluded that these components may be within the scope of license renewal and subject to an AMR. In a letter dated July 18, 2002, the staff requested that the applicant justify why these components were excluded from the scope of license renewal (RAI 2.3.3.15-3).

By letter dated October 3, 2002, the applicant responded that the subject screens, which are associated with the exhaust dampers, are provided for personnel safety only and have no impact on system operation. Furthermore, the only ductwork in the system is on the discharge side of the exhaust fans and is located outside the pump room on the roof of the intake structure. As such, these components do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff considers the applicant's response to this RAI to be acceptable on the basis that, since these components do not perform or support any system intended function, any degradation of these components resulting from aging will not prevent or impair the functioning of the Unit 2 intake structure ventilation system.

Miscellaneous Ventilation Staff Evaluation (Unit 1 Only). The staff reviewed the LRA and searched the UFSAR for St. Lucie Unit 1 but was unable to locate descriptive information for this system other than the single sentence provided in LRA Section 2.3.3.15. This sentence states that the miscellaneous ventilation systems provide ventilation for the Unit 1 computer room and hot shutdown panel. License renewal boundary drawing 1-HVAC-02 (locations C8, D8) shows a ventilation supply line from the CRVS to the computer room. By letter dated July 18, 2002, the staff requested that the applicant clarify why the computer room ventilation for Unit 1 is considered to be a separate subsystem under "miscellaneous ventilation" (RAI 2.3.3.15-6).

By letter dated October 3, 2002, the applicant responded that the CRVS provides only supply air to ventilate the computer room. Computer room ventilation is treated as a separate subsystem because its only intended function is to provide cooling for the computer room, which is within the control room envelope.

The staff considers the applicant's response to this RAI to be acceptable on the basis that treatment of the computer room ventilation system as separate, and not part of the CRVS, is an administrative issue and does not impact the identification of components that are within the scope of license renewal and subject to an AMR.

As discussed above, the staff questioned why several components were not listed in Table 3.3-15 of the LRA. A portion of the Unit 1 miscellaneous ventilation systems supply cooling for the hot shutdown panel, which is required to meet the Commission's FP regulations (10 CFR 50.48). Components required to perform this intended function are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2). By letter dated July 18, 2002, the staff requested, in part, that the applicant justify the omission of the intake screen for the hot shutdown panel ventilation outside air inlet (RAI 2.3.3.15-3).

The applicant's response to RAI 2.3.3.15-3 stated that the intake screen is actually mounted in a concrete plenum on the south side of the Unit 1 RAB, at plant elevation 26 feet 10 inches. The actual air intake for the fan is near the top of the plenum, at elevation 53 feet 8 inches. Due to this large elevation difference, failure of the intake screen would have no impact on the operation of the system. This screen does not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a) and thus is not within the scope of license renewal.

The staff found the applicant's response to the portion of RAI 2.3.3.15-3 that relates to the Unit 1 miscellaneous ventilation system to be acceptable on the basis that the physical layout of the ventilation inlet makes it unlikely that the ventilation capability will be significantly impacted by blockage of the screen. The vent inlet is downward facing and has a short through-wall section which opens onto a concrete plenum. The opening is too big to be credibly blocked by debris. The concrete plenum rises several feet before the opening to the hot shutdown panel ventilation intake. Any leaves and debris that enter the vent will most likely fall to the bottom of the concrete plenum and not block the flow path to the hot shutdown panel.

RAB Electrical and Battery Room Ventilation Staff Evaluation. During the initial review, the staff could not determine from the information contained in the LRA, the UFSAR, and the license renewal boundary drawings provided by the applicant which ventilation system supports and cools the Unit 2 hot shutdown panel and computer room. As a result, in a letter dated July 18, 2002, the staff requested that the applicant identify the system in question and clarify whether this system is within the scope of license renewal and subject to an AMR (RAI 2.3.3.15-9).

By letter dated October 3, 2002, the applicant responded that the Unit 2 RAB electrical equipment and battery room ventilation system provides ventilation to the hot shutdown panel and the computer room, and that this system and its components are within the scope of license renewal and listed in Table 3.3-15 of the LRA. The staff considers the applicant's response to this RAI to be acceptable on the basis that the applicant clarified that the components associated with the hot shutdown panel and computer room are listed in Table 3.3-15 as subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

RAB Main Supply and Exhaust Staff Evaluation. The staff has reviewed Section 2.3.3.15 of the LRA and Sections 9.4.2.2.1 and 9.4.3.2.1 of the UFSARs for St. Lucie Units 1 and 2, respectively. This review confirmed that the applicant has identified all components of the RAB main supply and exhaust system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). Based on this review, the staff finds that all components of this system that are within the scope of license renewal and subject to an AMR have been identified and are included in Table 3.3-15 of the LRA.

Shield Building Staff Evaluation. During the initial review of the SBVS, the staff found that certain components shown on the license renewal boundary drawings (cited below) as within the scope of license renewal were not listed as being subject to an AMR in Table 3.3-15. These components include electrical heating coils and housings for Unit 1 (locations D6 and F6 on 1-HVAC-02) and Unit 2 (locations D3, D4, and F3 on 2-HVAC-03), and demister housings for Unit 1 (locations D6 and F6 on 1-HVAC-02) and Unit 2 (locations D3 and F6 on 2-HVAC-03). By letter dated July 18, 2002, the applicant was requested, in part, to justify the omission of these components from Table 3.3-15 (RAI 2.3.3.15-3).

By letter dated October 3, 2002, the applicant responded that heating coils, being electrical components, are evaluated in LRA Section 2.5, while the housings for these coils are listed in Table 3.3-15 of the LRA under the component group "filter housings." Additionally, the applicant stated that demister housings are also included in the table under the component group "filter housings."

The staff considers the applicant's response to the applicable portions of this RAI to be acceptable on the basis that the applicant clarified that electrical heating coil housings and demister housings are within the scope of license renewal and are subject to an AMR and have been included in Table 3.3-15 in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

The staff review found that the components of the ventilation system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.15.3 Conclusion

Based on this review and additional information submitted by the applicant in response to the RAIs, the staff did not identify any omissions. The staff, therefore, concludes that there is reasonable assurance that the applicant has appropriately identified the ventilation system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Waste Management

2.3.3.16.1 Summary of Technical Information in the Application

In Section 2.3.3.16 of the LRA, the applicant identifies the components of the waste management system that are within the scope of license renewal and subject to an AMR. This system is described in Sections 9.3.3, 11.2.2, 11.3.2, and 11.5.2 of the Unit 1 UFSAR and in Sections 9.3.3, 11.2.2, 11.3.2, and 11.4.2 of the Unit 2 UFSAR. Protection against internal flooding of safety-related equipment is discussed in Appendix 3D of the Unit 1 UFSAR and Appendix 3.6F of the Unit 2 UFSAR.

The waste management system collects, monitors, and processes potentially radioactive reactor plant wastes prior to release or removal from the plant site. Waste management includes three subsystems, liquid, gaseous, and solid waste management. The waste management system also includes the safeguards pump room drains and equipment and floor drainage system.

Portions of the waste management system that form part of the containment and safeguards room boundary are within the scope of license renewal. These components generally have the intended function of pressure boundary, but other specific components are also included within the scope of license renewal because they have an FP intended function. For example, a segment of piping and an orifice in the Unit 1 RAB blowdown tank hallway that come from the hydrogen supply manifold (shown on drawing 1-WM-03 at location B6) are within the scope of license renewal and subject to an AMR. This piping segment and orifice have an FP intended function.

The waste management system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, non-safety-related SCs whose failure could prevent satisfactory accomplishment of the functions of safety-related SCs. SCs that are part of the EQ Program, or SCs that are relied on during fires.

Consistent with the method described in Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant listed the mechanical component types of the waste management system that are subject to an AMR in Table 3.3-16 of the LRA. Specifically, the applicant identified the component types subject to an AMR as valves (pressure boundary only), strainers, orifices, piping, and fittings. As discussed in Section 2.1 of this SER, the applicant identified additional pipe/fittings and valves of the waste management system as subject to an AMR in its September 26, 2002, response to RAI 2.1-1. The intended functions for waste management components subject to an AMR include pressure boundary, filtration, and throttling.

2.3.3.16.2 Staff Evaluation

The staff reviewed Section 2.3.3.16 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the waste management system that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.3-16 of the LRA to determine whether the applicant appropriately identified the components of the waste management system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the waste management system that were not listed in Table 3.3-16 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Sections 9.3.3, 11.2.2, 11.3.2, and 11.5.2 of the Unit 1 UFSAR and Sections 9.3.3, 11.2.2, 11.3.2, and 11.4.2 of the Unit 2 UFSAR and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.3.3.16 of the applicant's LRA.

During the review, the staff determined that certain floor drains were credited in the internal flooding analysis presented in Appendix 3D of the Unit 1 UFSAR and Appendix 3.6F of the Unit 2 UFSAR. Specifically, these floor drains were credited in the internal flooding analysis following breaks of moderate-energy pipelines in several rooms which contain safety-related equipment. (One example is the Unit 2 shutdown cooling heat exchanger room described on page 3.6F-4 of the Unit 2 UFSAR.) During the June 10—11, 2002, meeting (documented in the meeting summary dated July 31, 2002), the staff questioned why these drain lines were not highlighted to show that they are within the scope of license renewal on the referenced license renewal boundary drawings. The applicant clarified the status of these drains in its November 27, 2002, supplemental response to RAI 2.2-2 by stating that all floor drains in the reactor auxiliary and fuel handling buildings credited in the flooding analyses are within the scope of license renewal. The staff finds this response to be acceptable, as it confirms that these floor drains are within the scope of license renewal and subject to an AMR.

The staff review found that the components of the waste management system that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.3.3.16.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the waste management system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 System Scoping and Screening Results: Steam and Power Conversion Systems

2.3.4.1 Main Steam, Auxiliary Steam, and Turbine

2.3.4.1.1 Summary of Technical Information in the Application

In Section 2.3.4.1 of the LRA, the applicant identifies the components of the main steam, auxiliary, and turbine systems that are within the scope of license renewal and subject to an AMR. These systems are further described in Sections 10.2 and 10.3 of the UFSARs for Units 1 and 2, respectively. The steam and power conversion systems consist of the main steam, auxiliary steam, turbine, main Feedwater, auxiliary Feedwater, steam generator blowdown, and condensate systems and associated components.

The main steam system transports steam from the steam generators to the main turbines and other secondary steam system components. The main steam system has the intended functions of providing the principal heat sink for the RCS, protecting the RCS and the steam generators from overpressurization, providing isolation of the steam generators during steam line breaks, and supplying steam to the auxiliary Feedwater pump turbines.

Auxiliary steam has the intended function of providing pressure regulated and unregulated steam to plant auxiliary loads. Auxiliary steam isolates in certain high-energy line break scenarios.

The turbine for each unit, which includes the associated generator, converts the steam input from main steam to the plant's electrical output and provides first-stage pressure input to the reactor protection system. The turbine stop valves close during fires and SBO events.

The applicant stated that some of the license renewal boundaries for the main steam system were established at normally open valves, and that this approach was considered acceptable for the main steam system because the open boundary valves are required only to mitigate potential spurious valve operation in the unlikely event of certain fires. In accordance with plant procedures, these normally open valves are closed for fire scenarios. In addition, the steam supply piping to the Unit 2 auxiliary Feedwater turbine has drain lines with open throttle valves. These open valves prevent condensate/water accumulation in the piping and are throttled, such that leakage is insignificant and does not affect auxiliary Feedwater turbine performance.

Steam traps, by design, are closed valves that open to release any accumulated condensate/water. Once the condensate is removed, the steam trap (valve) automatically returns to the closed state.

The main steam, auxiliary steam, and turbine systems are in the scope of license renewal because they contain SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related whose failure could prevent satisfactory accomplishment of the safety-related functions, SCs that are part of the EQ Program, or SCs that are relied on during fires, SBO events, and ATWS events.

The applicant's listing of component types for the main steam, auxiliary steam, and turbine systems that are subject to an AMR in Table 3.4-1 of the LRA includes valves (pressure boundary only), steam traps, strainers, thermowells, orifices, piping, tubing, and fittings. The intended functions for the components of the main steam, auxiliary steam, and turbine system subject to an AMR are pressure boundary, filtration, and throttling.

2.3.4.1.2 Staff Evaluation

The staff reviewed Section 2.3.4.1 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the main steam, auxiliary steam, and turbine systems within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff reviewed the text, tables, and diagrams submitted by the applicant in Section 2.3.4.1 of the LRA and the UFSARs to determine whether any SCs of the main steam, auxiliary steam, and turbine systems that meet the scoping criteria in 10 CFR 54.4(a) may have been omitted from the scope of license renewal. The staff verified that those portions of the main steam, auxiliary steam, and turbine systems identified by the applicant as meeting the scoping requirements of 10 CFR 54.4(a). The staff then focused its review on those portions of the main steam, auxiliary steam, and turbine systems that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4(a). The staff also reviewed Sections 10.2 and 10.3 of the UFSARs to identify system intended functions that were not included in Section 2.3.4.1 of the LRA and verified that these intended functions did not meet the scoping requirements of 10 CFR 54.4(a). Therefore, there is reasonable assurance that the applicant appropriately identified portions of the St. Lucie main steam, auxiliary steam, and turbine systems that are within the scope of license renewal in accordance with 10 CFR 54.4(a).

The staff then determined whether the applicant had properly identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the components that are subject to an AMR for the main steam, auxiliary steam, and turbine systems and listed them in Table 3.4-1 of the LRA. The staff performed its review by sampling the components that the applicant identified as within the scope of license renewal but not subject to an AMR to verify that these components perform their intended functions with moving parts or with a change in configuration or properties or are subject to replacement based on qualified life or specified time period. Components reviewed by the staff met the above criteria for both units.

In Table 2.3-4 of the LRA, the applicant lists 10 license renewal boundary drawings that were highlighted to show the license renewal evaluation boundary for the main steam, auxiliary steam, and turbine systems. The staff compared the boundary drawings to the description in the UFSAR to ensure that the drawings were representative of the main steam, auxiliary steam, and turbine systems. The staff also sampled components shown on the boundary drawings that were not highlighted to ensure that these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.4.1 of the LRA, the staff determined that additional information was needed to complete its review. In Table 3.4-1 of the LRA, the applicant does not list certain components of the main steam, auxiliary steam, and turbine system, although license renewal boundary drawings identify them as being within the scope of license renewal. In particular, flexible hose connections SZ-08-1A1, SZ-08-1A2, SZ-08-1B1, and SZ-08-1B2, which are shown on drawing 1-MS-04 at locations D3 and H3, are passive and long-lived and, in accordance with 10 CFR 54.21(a)(1), should be subject to an AMR. In a letter dated July 18, 2002, the staff questioned the applicant about the above hose connections that appear to be subject to an AMR but were not included in Table 3.4-1 of the LRA. In its response dated October 3, 2002, the applicant clarified that the flexible hose connections are included as part of the instrument air system and are listed in Table 3.3-8 of the LRA.

The staff asked for additional information by letter dated July 18, 2002 (RAI 2.3.4-2), regarding the acceptability of ending license renewal boundaries at normally open valves, since failure of the downstream piping may affect the intended function of pressure boundary. Examples of locations where the boundary ended at normally opened valves include locations B1, B2, F4, F5, F6, and F7 on drawing 1-MS-02; location H5 on drawing 1-MS-03; locations B1, B2, F4, F5, F6, and F7 on drawing 2-MS-02.

The applicant responded to this question by letter on October 3, 2002. The applicant stated that these main steam line isolation valves are procedurally controlled, such that they will be manually closed in the event that a main steam isolation valve fails to automatically close during certain fire events. This procedure is in accordance with the St. Lucie Units 1 and 2 SSAs. Considering that the SSAs and plant procedures specifically address manual main steam isolation for these fire scenarios, this approach has been previously accepted as part of the CLBs for Units 1 and 2.

The staff finds the applicant's response to RAI 2.3.4-2 to be acceptable on the basis that manual closure of the subject valves is controlled by FP procedures, which were developed and reviewed by site safety personnel and are available for inspection by the NRC.

The staff's review found that the components of the main steam, auxiliary steam, and turbine systems that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.3.4.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the main steam, auxiliary steam and turbine systems components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Main Feedwater and Steam Generator Blowdown

2.3.4.2.1 Summary of Technical Information in the Application

In Section 2.3.4.2 of the LRA, the applicant identifies the components of the main Feedwater and steam generator blowdown systems which are within the scope of license renewal and subject to an AMR. These systems are further described in Sections 10.4.6 and 10.4.7 of the UFSAR for Unit 1 and Sections 10.4.7 and 10.4.8 of the UFSAR for Unit 2.

The main Feedwater and steam generator blowdown systems have the intended functions of providing sufficient water flow to the steam generators to maintain an adequate heat sink for the RCS, providing for main Feedwater and steam generator blowdown isolation following a LOCA or steam line break event, and assisting in maintaining steam generator water chemistry. Main Feedwater supplies preheated, high-pressure Feedwater to the steam generators at a rate equal to the main steam and steam generator blowdown flows. A three-element controller that determines the desired Feedwater flow by comparing the feed flow, steam flow, and steam generator level controls the Feedwater flow rate.

Steam generator blowdown assists in maintaining required steam generator chemistry by providing a means for removal of foreign matter that concentrates in the evaporator section of the steam generator. Steam generator blowdown is continuously monitored for radioactivity during plant operation.

The applicant stated that some of the license renewal boundaries for the steam generator blowdown system were established at normally open valves. The applicant considered this approach acceptable for the steam generator blowdown system because the normally open valves at license renewal boundaries are required only to mitigate potential spurious valve operation in the unlikely event of certain fires. Plant procedures require that these normally open valves be closed for fire scenarios.

The main Feedwater and steam generator blowdown system is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, SCs that are part of the EQ Program, SCs that are relied on during fire events, or SCs that are relied on during SBO events.

The applicant listed the component types for the main Feedwater and steam generator blowdown components subject to an AMR in Table 3.4-2 of the LRA, including valves (pressure boundary only), accumulators, orifices, thermowells, piping, tubing, and fittings. As discussed in Section 2.1 of this SER, the applicant identified additional pipe/fittings and valves of the main Feedwater and steam generator blowdown system as subject to an AMR in its September 26, 2002, response to RAI 2.1-1. The intended functions for main Feedwater and steam generator blowdown components subject to an AMR are pressure boundary and throttling.

2.3.4.2.2 Staff Evaluation

The staff reviewed Section 2.3.4.2 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the main Feedwater and steam generator blowdown systems within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 54.21(a)(1), respectively.

The staff reviewed the text, tables, and diagrams submitted by the applicant in Section 2.3.4.2 of the LRA and the UFSARs to determine whether any SCs of the main Feedwater and steam generator blowdown systems that meet the scoping criteria in 10 CFR 54.4(a) may have been omitted from the scope of license renewal. The staff verified that those portions of the main Feedwater and steam generator blowdown systems identified by the applicant as meeting the scoping requirements of 10 CFR 54.4 meet these requirements for both Units 1 and 2. The staff then focused its review on those portions of the main Feedwater and steam generator blowdown systems that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed Sections 10.4.6 and 10.4.7 (Unit 1) and Sections 10.4.7 and 10.4.8 (Unit 2) of the UFSARs to identify system intended functions that were not included in Section 2.3.4.2 of the LRA and verified that these intended functions did not meet the scoping requirements of

10 CFR 54.4(a). Therefore, there is reasonable assurance that the applicant appropriately identified portions of the main Feedwater and steam generator blowdown systems that are within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified components that are subject to an AMR for the main Feedwater and steam generator blowdown systems and listed them in Table 3.4-2 of the LRA. The staff performed its review by sampling the components that the applicant identified as within the scope of license renewal but not subject to an AMR to verify that these components perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period. Components reviewed by the staff met the above criteria for both units.

In Table 2.3-4 of the LRA, the applicant lists 11 license renewal boundary drawings that were highlighted to show the license renewal evaluation boundary for the main Feedwater and steam generator blowdown systems. The staff compared the boundary drawings to the description in the UFSAR to ensure that the drawings were representative of the main Feedwater and steam generator blowdown systems. The staff also sampled components shown on the boundary drawings that were not highlighted to ensure that these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.4.2, the staff determined that additional information was needed from the applicant. On license renewal boundary drawing 1-FW-02, the main Feedwater isolation valve accumulators for Unit 1 are shown to be within the scope of license renewal; however, they are not listed in Table 3.4-2 of the LRA as being subject to an AMR. The accumulators for Unit 2 are listed in the table as being subject to an AMR.

In a letter dated July 18, 2002, the staff asked the applicant why the Unit 1 accumulators described above were not subject to an AMR since they performed an intended function. In its response dated October 3, 2002, the applicant stated that the Unit 1 accumulators shown on license renewal boundary drawing 1-FW-02 are included as part of the instrument air system and are listed in Table 3.3-8 of the LRA. The staff finds the applicant's response acceptable as it clarifies that the Unit 1 accumulator components are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff review found that the components of the main Feedwater and steam generator blowdown systems that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.4.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the main Feedwater and steam generator blowdown systems components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Auxiliary Feedwater and Condensate

2.3.4.3.1 Summary of Technical Information in the Application

In Section 2.3.4.3 of the LRA, the applicant identifies the components of the auxiliary Feedwater and condensate systems that are within the scope of license renewal and subject to an AMR. These systems are further described in Sections 10.5.1 and 9.2.8 of the Unit 1 UFSAR and Sections 10.4.9 and 9.2.6 of the Unit 2 UFSAR.

The auxiliary Feedwater system has the intended function of supplying Feedwater to the steam generators when normal Feedwater sources are not available. Auxiliary Feedwater for each unit contains two motor-driven pumps and one steam-turbine-driven pump. The pumps take suction from the condensate storage tank (CST) and discharge to the steam generators. Auxiliary Feedwater is normally maintained in standby. Upon initiation, all three pumps on the affected unit start to supply the steam generators with Feedwater.

The condensate system includes the CST that stores water for use by auxiliary Feedwater to support safe shutdown of the plant. The CSTs are cross-connected between the units.

Auxiliary Feedwater and condensate systems are in the scope of license renewal because they contain SCs that are safety-related and are relied upon to remain functional during and following DBEs, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs, SCs that are part of the EQ Program, or SCs that are relied on during fires, SBO, and ATWS events.

The applicant listed the component types for the auxiliary Feedwater and condensate systems subject to an AMR in LRA Table 3.4-3, including tanks, pumps, turbines, and valves (pressure boundary only), coolers, orifices, vortex breakers, sight glasses, piping, tubing, and fittings. As discussed in Section 2.1 of this SER, the applicant identified additional pipe/fittings and valves of the auxiliary Feedwater and condensate systems as subject to an AMR in its September 26, 2002, response to RAI 2.1-1. The intended functions for auxiliary Feedwater and condensate components subject to an AMR are pressure boundary, heat transfer, vortex prevention, and throttling.

2.3.4.3.2 Staff Evaluation

The staff reviewed Section 2.3.4.3 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the auxiliary Feedwater and condensate systems within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff reviewed the text, tables, and diagrams submitted by the applicant in Section 2.3 of the LRA and the UFSARs to determine whether any SCs of the auxiliary Feedwater and condensate systems that meet the scoping criteria in 10 CFR 54.4(a) may have been omitted from the scope of license renewal. The staff verified that those portions of the auxiliary Feedwater and condensate systems identified by the applicant as meeting the scoping requirements of 10 CFR 54.4(a) meet these requirements for both units. The staff then focused its review on those portions of the auxiliary Feedwater and condensate systems that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4(a). The staff also reviewed Sections 10.5.1 and 9.2.8 of the Unit 1 UFSAR and 10.4.9 and 9.2.6 of the Unit 2 UFSAR to identify system intended functions that were not included in Section 2.3.4.3 of the LRA, and verified that these functions did not meet the scoping requirements of 10 CFR 54.4(a).

The staff then determined whether the applicant had appropriately identified the in-scope SCs that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the SCs that are subject to an AMR for the auxiliary Feedwater and condensate systems and listed them in Table 3.4-3 of the LRA. The staff performed its review by sampling the SCs that the applicant identified as within the scope of license renewal, but not subject to an AMR to verify that these SCs perform their intended functions with moving parts or with a change in configuration or properties or are subject to replacement based on qualified life or specified time period. The SCs reviewed by the staff met the above criteria for Units 1 and 2.

In Table 2.3-4 of the LRA, the applicant lists two license renewal boundary drawings for each unit that were highlighted to show the license renewal evaluation boundary for the auxiliary Feedwater and condensate systems. The staff compared the boundary drawings to the description in the UFSAR to ensure that the boundary drawings were representative of the auxiliary Feedwater and condensate systems for Units 1 and 2. The staff also sampled portions of the boundary drawings that were not highlighted to ensure that these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

During its review of Section 2.3.4.3, the staff determined that additional information was needed to complete its review. On license renewal boundary drawings 1-AFW-01 and 2-AFW-0 (at location D7), the applicant indicates that piping from the CST connects below the normal water level. The piping appeared to connect the lower portion of the CST with the condenser hotwell; failure of this piping could compromise the pressure boundary intended function of the CST. The applicant does not show on the boundary drawings that the piping is within the scope of license renewal. In a letter dated July 18, 2002, the staff asked the applicant to justify why this CST piping is considered not to be within the scope of license renewal and not subject to an AMR.

In its response dated October 3, 2002, the applicant stated that license renewal boundary drawings should not be used to ascertain CST connection elevations for piping. The applicant cited from its plant technical specifications that the Unit 1 CST requires a minimum level of 439 m^3 (116,000 gallons), and the Unit 2 CST requires a minimum level of 1,162 m^3 (307,000 gallons). Non safety-related lines connected to these CSTs utilize penetrations located above the minimum water levels, as required by technical specifications, such that assumed failures of these lines will not compromise the pressure boundary intended function of the CSTs.

The staff agrees with the applicant's conclusion that the non safety-related lines connected to the CSTs are not within the scope of license renewal on the basis that they do not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a).

The staff's review found that the components of the auxiliary Feedwater and condensate systems that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.4.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the auxiliary Feedwater and condensate systems components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.5 Expanded SSCs Scoping

Section 54.4(a)(2) of 10 CFR Part 54 requires that all non safety-related SCs whose failure could prevent satisfactory accomplishment of any of the safety-related functions identified in 10 CFR 54.4(a)(1) be included within the scope of license renewal. In part, 10 CFR 54.4(a)(3) requires that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for SBO be included within the scope of license renewal.

2.3.5.1 Summary of Technical Information in the Application

In Section 2.1 of the LRA, the applicant described scoping and screening methodology for identifying SSCs that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(2). In Sections 2.3 and 2.4 of the LRA, the applicant provided its scoping and screening results and identified the SSCs that are within the scope of license renewal and subject to an AMR.

Section 2.1.1.3 of the LRA indicates that seismic supports are considered for Criterion 2 scoping of non safety-related mechanical components. However, contrary to the staff's position described in the interim staff guidance dated December 3, 2001, and March 15, 2002, regarding 10 CFR 54.4(a)(2) and the seismic II/I issue, the applicant did not consider the potential for non-safety-related piping and components to have spatial interactions with safety-related components. Additionally, the applicant did not fully consider the staff's position on SBO described in the interim staff guidance dated April 1, 2002.

Based on its review of the information provided in Section 2.1 of the LRA, the staff requested additional information in RAIs 2.1-1 and 2.1-2, dated July 1, 2002. In RAI 2.1-1, the staff asked the applicant to describe the scoping methodology implemented for the evaluation of the criterion defined in 10 CFR 54.4(a)(2). In addition, the applicant was asked to indicate the option(s) credited, list the SSCs included within scope, list those SCs for which AMRs 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. In RAI 2.1-2, the staff asked the applicant to describe the process used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3). The applicant was also asked to (1) list those additional SSCs included within scope as a result of the SBO evaluation, (2) list those SCs for which AMRs were conducted, and (3) describe (as applicable for each structure or component) the AMPs that will be credited for managing the identified aging effects.

By letter dated September 26, 2002, the applicant responded to the staff's RAIs. In its response to RAI 2.1-1, the applicant stated that the five components and structural components described below have been included in the scope of license renewal to protect safety-related SSCs from a failure of non-safety-related piping systems and other SSCs (scoping criteria 10 CFR 54.4(a)(2)).

(1) non-safety-related piping segments and supports at safety-related/non-safety-related functional boundaries that extend beyond the system pressure boundary component to ensure the integrity of the safety-related/non-safety-related functional system pressure boundary (Tables 3.5-1 through 3.5-16)

(2) piping/component supports for non-safety-related mechanical systems with the potential of "seismic II over I" interaction with safety-related components (Tables 3.5-1 through 3.5-16)

(3) non-safety-related conduit, cable trays, supports, and other structural components with the potential of "seismic II over I" interaction with safety-related components (Tables 3.5-1 through 3.5-16)

(4) design features required to accommodate the effects of flooding, such as curbing, platforms, sumps, sump pumps, and drains (Tables 3.5-1 through 3.5-16, Table 3.3-13, and Table 3.3-16)

(5) design features required to accommodate the effects of spray, jet impingement, and pipe whip, such as pipe whip restraints and internal barriers (Tables 3.5-1 through 3.5-16)

In its response to RAI 2.1-2, the applicant performed an evaluation to determine the additional electrical and structural components that are within the scope of license renewal for restoration of offsite power at St. Lucie. An AMR evaluation was also performed for the electrical and structural components determined to be within the scope of license renewal and requiring an AMR.

2.3.5.2 Staff Evaluation

The staff's evaluation of the applicant's scoping methodology is presented in Section 2.1.3.1 of this SER. The evaluation of the associated SSCs initially identified in each LRA (Sections 2.3 and 2.4 of this SER) includes the expanded SCs for nine mechanical systems and structures for three buildings or areas that were originally within the scope of license renewal, but whose boundaries were expanded in the applicant's RAI response dated September 26, 2002. Components of two additional non safety-related piping systems were brought into scope in the applicant's RAI response. They are the demineralized water system for Unit 1 (Unit 2 was already in scope as discussed in Section 2.3.3.3 of this SER), and the Unit 1 heater drains and vents system. Additional structures for one new area, the switchyard, were also brought into scope.

The following staff evaluation focuses on the non safety-related piping systems that have a spatial relationship to safety-related components, such that their failure could adversely impact the performance of an intended safety function. Specifically, the staff reviewed the applicant's scoping method in Section 2.1.3.1 of this SER. The following discussion focuses on the results obtained for the expanded scope SSCs added in response to RAIs 2.1-1 and 2.1-2.

The scoping method described in that RAI response includes several steps to identify the second configuration non safety-related piping systems. In the first step, the applicant identified the following structures that contain both safety-related and non safety-related SSCs.

- containments
- component cooling water areas
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fuel handling buildings
- intake structures
- RABs
- steam trestle area
- turbine building (Unit 1 only)
- ultimate heat sink dam
- yard structures

Section 2.1.1.3 of the LRA, "Non-Safety-Related Criteria Pursuant to 10 CFR 54.4(a)(2)," states that in the case of "seismic II over I," or the potential for non safety-related SSCs to fail and prevent a safety function, the non safety-related SSC must be supported in a manner to prevent it from falling on safety-related systems or components. Thus, the supports for these SSCs were included within the scope of license renewal. However, in response to staff RAI 2.1-1, the applicant reviewed the locations of non-safety-related SSCs relative to the safety-related SSCs, using an area-based approach.

The component and structural component level scoping performed as part of the screening process then established the specific non-safety-related seismic interaction component, or structural component types, located within the structure for inclusion in the license renewal scope. Those items determined to have an interaction were included within the scope of license renewal, and AMRs were performed and summarized in tables similar to those contained in the LRA. Revised tables were presented that expanded the boundaries for nine mechanical systems previously identified as being in the scope of license renewal.

Systems with expanded boundaries for Unit 1 only included primary makeup water, main Feedwater, and auxiliary Feedwater and condensate.

Systems with expanded boundaries for Unit 2 only included demineralized makeup water.

Systems with expanded boundaries for both Units 1 and 2 included chemical and volume control, component cooling water, sampling, service water, and waste management.

In addition, two additional systems (1) heater drains and vents and (2) demineralized makeup water were brought into scope for Unit 1. The heater drains and vents system applies only to Unit 1, because only the turbine building for Unit 1 contains safety-related components that are within the scope of license renewal. As identified in the applicant's response to RAI 2.1-1, the components of this system that are within the scope of license renewal and subject to an AMR include piping/fittings and valves. The intended function of these components is pressure boundary.

In the RAI 2.1-1 response, the applicant stated that on the basis of its evaluation, as described above and performed consistent with the guidance of the March 15, 2002, NRC letter regarding 10 CFR 54.4.(a)(2) scoping, components added to the scope of license renewal and subject to an AMR have been included in Tables 2.1-1 (emergency diesel generator building), 2.1-2 (reactor auxiliary buildings), 2.1-3 (turbine building - Unit 1 only), and 2.1-4 (yard structures).

As noted in the tables, the appropriate AMPs have been revised to include these components. As shown in the RAI response, the tables include component groups such as pipe/fittings, valves, and bolting (mechanical enclosures).

Additional components and structures were also brought into scope by the applicant in response to RAI 2.1-2. One new area, the switchyard, was added, and additional components were included for the turbine buildings and yard structures. Consistent with the NRC position, the following additional structural components are included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(3) for restoration of offsite power.

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

Turbine buildings

- switchgear rooms
- switchgear enclosures
- switchgear supports
- nonsegregated-phase bus supports

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 Table 3.5-16

In its response to RAI 2.1-2 dated September 26, 2002, the applicant stated that, on the basis of its evaluation, which was performed consistent with the guidance of the April 1, 2002, NRC letter regarding scoping for SBO for license renewal, it has added structural components to the scope of license renewal and subject to an AMR in Tables 2.1-6 (switchyard), 2.1-7 (turbine building), and 2.1-8 (yard structures). As noted in the tables, the appropriate AMP has been revised to include these structural components. As shown in the RAI response, the tables include structural component groups such as startup transformer circuit breaker foundations, switchgear rooms, transmission towers, and nonsegregated phase bus supports.

The results of this expanded scoping were also reviewed by the NRC regional inspection team during an inspection held October 21 through 25, 2002. The inspection team reviewed the applicant's engineering evaluation, selected plant layout drawings as marked up, and documentation for portions of SCs added to the scope of license renewal. The inspection team also walked down areas of the plant that did not contain additional in-scope systems/components and some areas where additional in-scope systems/components had been added. The inspection team determined that the applicant's scoping and screening activities were performed in accordance with the prescribed methodology and were adequate. In Inspection Report 2002-07, dated November 27, 2002, the inspection team reviewed the implementation of the applicant's methodology for identifying the portions of systems not originally included in scope and added as a result of RAIs 2.1-1 and 2.1-2.

The staff reviewed the applicant's responses to RAIs 2.1-1 and 2.1-2, the list of SSCs included within the scope of license renewal, and the findings of the NRC inspection team. Based on the above, the staff finds the expanded scope SSCs identified in the RAI responses to be acceptable because the applicant included all the non safety-related SSCs with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) (seismic II over I) and 10 CFR 54.4(a)(3) (SBO), as discussed in the applicant's response to these RAIs. The staff concluded that the portions of the applicant's response to RAIs 2.1-1 and 2.1-2 that relate to the scoping and screening results as described above is acceptable. This conclusion is based on the RAI response and the inspection report confirmation that these non-safety-related piping segments and supports were included in the scope, as well as on the staff position stated in the Interim Staff Guidance for Seismic II/I, dated December 3, 2001, and SBO, dated April 1, 2002.

On the basis of its review of the information contained in the RAI responses and its confirmation from the inspection, the staff did not identify any omissions in the scoping and screening of the expanded 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3) SSCs.

2.3.5.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

Therefore, the staff concludes that there is a reasonable assurance that the applicant has identified those SSCs that are within the scope of license renewal, as well as the SCs that are subject to an AMR, in accordance with 10 CFR 54.4(a)(2), 10 CFR 54.4(a)(3), and 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section addresses the staff's review of the results of the scoping and screening methodology for structures. The structures consist of the following components.

Containments

- containment vessels
- reactor containment shield buildings
- reactor containment shield building interior components

Other Structures

- component cooling water areas
- condensate polisher building
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fire rated assemblies
- fuel handling buildings
- fuel handling equipment
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

In accordance with the requirements stated in 10 CFR 54.21(a)(1), the applicant must identify and list structures and components subject to an AMR. These are passive, long-lived structures and components that are within the scope of license renewal. To verify that the applicant properly implemented its methodology, the staff reviewed the scoping and screening results to confirm that there was no omission of structures or components that are subject to an AMR.

2.4.1 Containments

In Section 2.4.1.1, "Containment Vessels," Section 2.4.1.2, "Reactor Containment Shield Buildings," and Section 2.4.1.3, "Reactor Containment Shield Building Interior Components" of the LRA, the applicant describes the SCs of the containment and reactor shield buildings at each St. Lucie unit. The containment and reactor shield buildings are further described in Section 3.8.2 of the UFSARs for St. Lucie Units 1 and 2. The applicant grouped the component types that are within the scope of license renewal and subject to an AMR in Table 3.5-2 of the LRA for all three structures that comprise the containment. These structures are (1) the containment vessels, (2) the reactor containment shield building, and (3) the reactor containment shield building interior components (including fuel handling equipment and tools located inside the containment).

In Table 3.5-2, the applicant identifies the SCs subject to an AMR as containment vessels, structural steel framing, stairs, ladders, platforms, handrails, checkered plate, grating, component supports, reactor vessel supports, pressurizer supports, RCP supports, steam generator supports, air-tight bulkhead doors (shield building), maintenance hatch outside doors, equipment and personnel hatches (maintenance hatches, personnel hatches, and escape hatches) including hinges, latches, and equalizing valves, piping and spare penetrations (includes bellows), fuel transfer tube penetration sleeves, fuel transfer tubes and expansion bellows, reactor cavity seal rings, refueling pool liner plates, fuel transfer flange supports, fuel transfer system (Unit 2 only), electrical penetrations, heating and ventilation penetrations, fuel transfer tube isolation flanges, passive components of the polar cranes, telescoping jib cranes, other cranes and hoists, refueling machines, conduits and cable trays, conduit and cable tray supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, HVAC duct supports, tubing supports, trisodium phosphate baskets (Unit 2 only), pipe and component supports, non-safety-related pipe segments between class break and seismic anchor, pipe whip restraints, recirculation sump screens, miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.), reinforced concrete structures above ground water (exterior walls and roofs), reinforced concrete structures below ground water (exterior walls and foundation), other reinforced concrete structures (i.e., interior shield walls, beams, slabs, missile shields, equipment pads, etc.), masonry block walls, containment vessel moisture barriers, reactor cavity seal ring seals, containment hatch seals and gaskets, airtight bulkhead door seals, fuel transfer tube penetration flexible membranes (in annulus), and lubrite sliding supports.

The Unit 1 and 2 containments are within the scope of license renewal because they are seismic Category 1 structures designed to shelter and house the RCS and to prevent the uncontrolled release of radioactivity. The containment vessel is the third and final barrier against possible release of radioactive material to the environment during the unlikely event of failure of the RCS. The low-leakage steel containment shell and penetrations are designed to confine radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary.

The intended functions of the containment SCs (a composite of the three sections of the LRA sections noted above) that are in the scope of license renewal are listed in Table 3.5-2 of the LRA and again below.

- provide a pressure boundary
- provide structural support to safety-related components
- provide shelter/protection to safety-related components (including radiation shielding)
- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related SCs whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs
- provide flood protection barriers
- provide a boundary for safety-related system ventilation
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO
- provide restraints for pipe whipping and/or protect systems and equipment from jet impingement

The staff reviewed Sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 of the LRA pertaining to the St. Lucie containments and related sections of the UFSARs to determine whether there is reasonable assurance that the applicant has identified and listed the SCs within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

2.4.1.1 Containment Vessels

2.4.1.1.1 Summary of Technical Information in the Application

In Section 2.4.1.1 of the LRA, the applicant describes the SCs of the containment vessels that are within the scope of license renewal and subject to an AMR. The containment vessels are further described in Section 3.8.2 of the UFSARs for Units 1 and 2. The containments for Units 1 and 2 consists of a freestanding steel containment vessel structure surrounded by the reactor containment shield building. In Section 2.4.1.1 of the LRA, the applicant describes major components of the containment vessel including the containment vessel structure, mechanical penetrations, electrical penetrations, airlocks and hatches, and the fuel transfer tubes.

The containment houses the RCS, which includes the reactor pressure vessel, the reactor coolant piping and pumps, the steam generators, the pressurizer and pressurizer quench tank, the SI tanks, the RCS supports, and other important systems that interface with the RCS. The containment also houses and supports the components required for plant refueling, including the polar crane, refueling cavity, and portions of the fuel handling system. The containment vessel and its attachments meet the license renewal scoping criteria of 10 CFR 54.4(a) because they perform the intended functions of providing (1) provide a leak-tight barrier to prevent uncontrolled release of radioactivity, (2) structural or functional support of safety-related SSCs, and (3) shelter or protection of safety-related equipment.

Containment Vessel Structures. Each containment vessel is a low-leakage steel shell structure designed to confine radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary. The containment vessel structure is a right circular cylinder with a hemispherical dome and an ellipsoidal bottom.

Mechanical Penetrations. Mechanical penetrations are provided for passage of process, service, sampling, and instrumentation piping into the containment vessel while maintaining containment integrity and providing a leak-tight seal. The mechanical penetration assemblies typically consist of a containment vessel penetration nozzle, a process pipe, a shield building penetration sleeve, and a shield building bellows seal. For cold penetrations, the containment vessel penetration nozzle is an integral part of the process pipe. For hot or semi-hot penetrations, a multiple flued head is provided as an integral part of the process pipe. A guard pipe is welded to the flued head. In addition, for hot penetrations, an expansion joint bellows is welded to the flued head and the containment vessel penetration nozzle to accommodate thermal movement. At the terminal piping penetration assembly near the reactor containment shield building, a low-pressure leakage barrier is provided to form a shield building bellows seal. The bellows provides a flexible membrane type closure between the shield building penetration sleeve, which is embedded in the reactor containment shield building, and the process pipe.

Electrical Penetrations. All electrical conductors that penetrate through the containment vessel, annulus, and reactor containment shield building use canister or header plate type assemblies. The primary containment penetration is inserted in the containment vessel nozzle and is field welded inside the steel vessel to form the sealing weld. The secondary seal is inserted in a nozzle embedded in the concrete shell of the reactor containment shield building. The secondary shield is welded to the nozzle in the reactor containment shield building. The primary containment penetrations feature hermetic cable sealing achieved by ceramic, glass, or high-temperature thermoplastic material bonding to a metal flange. The flange is welded to a header plate, which is welded to the penetration nozzle. Either epoxy resin or thermoplastic material forming a continuous seal between the metal canister and all conductors achieves the secondary seal.

Airlocks and Hatches. Two equipment hatches, a construction hatch and a maintenance hatch, are provided for each containment vessel. The construction hatch for each unit is a welded steel assembly with a welded construction hatch cover. The maintenance hatch is a welded assembly with a double gasketed flanged and bolted hatch cover. Two personnel airlocks are provided for each containment vessel. These are welded steel tube assemblies. Each airlock has a double gasketed door at each end of the tube.

Fuel Transfer Tubes. Each unit has a fuel transfer tube to transfer fuel assemblies between the refueling cavity in the containment and the SFP in the fuel handling buildings during refueling operations. The fuel transfer tube penetration consists of a stainless steel transfer tube installed in a concentric carbon steel pipe sleeve. The fuel transfer tube is fitted with a double gasketed blind flange in the containment and a standard gate valve in the fuel handling building. The pipe sleeve is welded to the containment vessel. Three bellows are provided in the containment and one bellows in the fuel handling building. A flexible membrane expansion joint is provided to compensate for building settlement and differential motion between the containment vessel, the reactor containment shield building, and the fuel handling building.

2.4.1.1.2 Staff Evaluation

The staff reviewed Section 2.4.1.1 of the LRA and associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the SCs of the containment vessels that are within the scope of license renewal, in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.5-2 of the LRA to determine whether the applicant appropriately identified the components of the containment vessels that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the containment vessels that were not listed in Table 3.5-2 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 3.8.2 of the UFSARs for Units 1 and 2 and did not identify any intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.1.1 of the LRA.

During the review, the staff questioned the applicant's omission of certain passive and long-lived structural components from Table 3.5-2 of the LRA. By letter dated July 1, 2002, the staff questioned the omission of a manway shown on the top of the steel containment structure at location B5 on general arrangement drawings 8770-G-067 (Unit 1 UFSAR, Figure 1.2-10) and 2998-G-067 (Unit 2 UFSAR, Figure 1.2-10) (RAI 2.4.1-1). This manway and associated closure bolting and gaskets are not listed in Table 3.5-2. The staff asked the applicant to justify why these components are not within the scope of license renewal and subject to an AMR, as these components appear to form a portion of the containment pressure boundary.

By letter dated October 3, 2002, the applicant responded that the manways are permanently welded to the containment vessels, similar to the construction hatches. The manways are considered part of the containment vessels listed in Table 3.5-2 of the LRA (page 3.5-35) and are not listed separately. Thus, the manways are included within the scope of license renewal, are subject to an AMR, and were evaluated with the containment vessels. The staff finds the applicant's response to be acceptable on the basis that it clarifies that the above components are in the scope of license renewal and subject to an AMR.

In the letter dated July 1, 2002, the staff asked the applicant to justify the omission of a structural material identified as Ethafoam (RAI 2.4.1-2), shown between the containment vessel and concrete in general arrangement drawings 8770-G-067 (Unit 1 UFSAR, Figure 1.2-10) and 2998-G-067 (Unit 2 UFSAR, Figure 1.2-10) at locations K1, K10, and I15 on both drawings, from the scope of license renewal and an AMR. The staff stated that in Table 3.5-2 of the LRA, the applicant identified the containment vessel moisture barrier component, made of elastomer, as within the scope of license renewal. The Ethafoam material has a similar intended function as the moisture barrier, in that it is to "provide shelter/protection to safety-related components (including radiation shielding)." (Ethafoam is a polyethylene foam.)

By letter dated October 3, 2002, the applicant responded that the Ethafoam material is associated with the containment vessel moisture barriers noted in Section 2.4.1.1 of the LRA (on page 3.5-14). The moisture barrier detail calls for Ethafoam material covered by a joint sealer (elastomer) between each steel containment vessel and the concrete floor at elevation 23 feet. The purpose of the Ethafoam material is to occupy the void space between the concrete and the steel vessel during construction. The purpose of the joint sealer is to prevent moisture intrusion between the concrete and the steel vessel. Therefore, the elastomer joint sealer is included in Table 3.5-2 of the LRA as "containment vessel moisture barriers" because it performs the intended function of excluding moisture. The Ethafoam material is not included in Table 3.5-2 because it does not perform or support any intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). The staff finds the applicant's response to be acceptable on the basis that it clarifies that the Ethafoam material does not perform any intended function as defined in 10 CFR 54.4(a).

The status of the containment and shield building penetrations were discussed during a meeting with the applicant on May 15 to 16, 2002. The containment and shield building penetrations are components of a number of systems and are shown on many of the license renewal boundary drawings. As a result, the containment and shield building penetrations are listed as subject to an AMR in many LRA sections (including mechanical penetrations, containment cooling, containment spray, containment isolation, SI, CVCS, component cooling water, instrument air, sampling, ventilation, main steam, feedwater, and auxiliary feedwater). Because of the large number of license renewal drawings and LRA sections with containment penetrations, the staff was unable to determine with reasonable assurance that all of the containment and shield building penetrations shown in Table 6.2-16 of the Unit 1 UFSAR and Table 6.2-52 of the Unit 2 UFSAR were within the scope of license renewal.

As documented in a summary (dated July 1, 2002) of the May 15 through 16, 2002, meeting, the applicant referred the staff to page 2.3-11 of the LRA, which states that, "all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described, require an AMR." The staff finds this response to be acceptable, as it confirms that the containment penetrations and associated components are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In a letter dated July 1, 2002, the staff questioned the applicant about the omission of certain hatches as subject to an AMR (RAI 2.4.1-3). In Section 2.4.1.1.4 of the LRA, the applicant states that two equipment hatches, a construction hatch and a maintenance hatch, are provided for each containment vessel. The applicant further states that two personnel airlocks are provided for each containment vessel. Section 3.5.1.1 and Table 3.5-2 of the LRA list maintenance, personnel, and escape hatches. Outside doors for maintenance hatches are also noted; however, construction hatches are not explicitly included. The staff asked why the construction hatch is not identified in Section 3.5.1.1 and Table 3.5-2 of the LRA.

By letter dated October 3, 2002, the applicant responded that the construction hatches are permanently welded shut and are, therefore, considered part of the containment vessels listed in Table 3.5-2 of the LRA. The two personnel airlocks for each containment described in Section 2.4.1.1.4 of the LRA are the personnel hatch and the escape hatch in Table 3.5-2. The staff finds the applicant's response to be acceptable on the basis that all containment hatches and airlocks are included in the scope of license renewal and are subject to an AMR.

In the performance of the review, the staff focused on components that were not identified as subject to an AMR. The staff considered the system functions described in the UFSAR to determine whether components having intended functions meeting the criteria of 10 CFR 54.4(a) were omitted from the scope of license renewal. In meetings with the applicant on May 15 through 16, 2002, the staff observed that the fuel transfer tubes are shielded with lead shot (shown on general arrangement Figure 1.2-8 of the Unit 1 UFSAR at location C15). Lead shielding is also shown in the vicinity of the refueling cavity (shown on general arrangement Figure 1.2-8 of the Unit 2 UFSAR at location C16). However, none of the component types listed in Table 3.5-2 of the LRA identifies components composed of lead or lead shot materials. If shielding components made of lead and lead shot materials have a safety-related intended function, they should be in the scope of license renewal and subject to an AMR.

In response, the applicant indicated that in Section 12.3.1.5 of the Unit 1 UFSAR and Section 12.3.1.6 of the Unit 2 UFSAR, the lead shielding is described as being installed for the purpose of personnel protection. The staff finds the applicant's omission of these components acceptable on the basis that the lead shot shielding does not perform any intended function as defined in 10 CFR 54.4(a).

The staff's review found that the SCs of the containment vessels that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.1.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the containment vessels, including containment vessel structures, mechanical penetrations, electrical penetrations, airlocks and hatches, and fuel transfer tubes structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.1.2 Reactor Containment Shield Buildings

2.4.1.2.1 Summary of Technical Information in the Application

In Section 2.4.1.2 of the LRA, the applicant describes the SCs of the reactor containment shield building that are within the scope of license renewal and subject to an AMR. The reactor containment shield buildings are described in Section 3.8.2.2.1 of the Unit 1 UFSAR and Section 3.8.4.1.1 of the Unit 2 UFSAR. The reactor containment shield building is a reinforced concrete right cylinder structure with a shallow dome roof surrounding the containment vessel. Each reactor containment shield building is a freestanding structure, with concrete fill placed in the bottom portion of the structure to support the steel containment vessel. The reactor containment shield building protects the containment vessel from external missiles, provides biological shielding, collects fission products that may leak from the containment vessel following an accident, and provides environmental protection for the containment vessel.

The containment vessel and reactor containment shield building are supported by a common base slab. The reactor containment shield building cylinder wall is directly supported by the base slab. The steel containment vessel is supported on fill concrete that transfers the loads by bearing to the base slab. To assure proper contact between the containment vessel and the concrete, the interface is grouted with epoxy.

2.4.1.2.2 Staff Evaluation

The staff reviewed Section 2.4.1.2 of the LRA and associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the SCs of the reactor shield building that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.5-2 of the LRA to determine whether the applicant appropriately identified the components of the reactor containment shield building that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those SCs of the reactor shield building that were not listed in Table 3.5-2 to verify that the applicant properly identified the SCs that meet the above requirements. The staff also reviewed Section 3.8.2.2.1 of the Unit 1 UFSAR and Section 3.8.4.1.1 of the Unit 2 UFSAR and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.1.2 of the LRA.

During the review, the staff determined that additional information was needed to complete its evaluation. In Section 2.4.1.2 of the LRA, the applicant states that the steel containment vessel is supported on fill concrete that transfers the loads by bearing to the base slab. The component group "reinforced concrete below ground water (exterior walls and foundation)," listed in Table 3.5-2 of the LRA, describes the base slab. However, it is not clear whether this same description also applies to fill concrete between the containment vessels and the base slab. The fill concrete provides structural support to the containment vessel and, as such, should be within the scope of license renewal and subject to an AMR. In a letter dated July 1, 2002, the staff asked the applicant to clarify the component type that applies to fill concrete (RAI 2.4.1-1).

By letter dated October 3, 2002, the applicant responded that the fill concrete between the containment vessels and the base slabs is included in Table 3.5-2 of the LRA as part of the "reinforced concrete below ground water" component group. The staff finds the response to be acceptable on the basis that it clarifies that the fill concrete is in the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In a letter dated July 1, 2002, the staff asked the applicant to justify the omission of the main plant vent stacks from being subject to an AMR (RAI 2.4.1-6). The plant vent stacks are components of the SBVSs but are also large structures attached to the exterior of the reactor shield buildings. In the LRA, the applicant states that these components are not within the scope of license renewal and are not subject to an AMR for several reasons.

Page 2.3-26 of the LRA states, "considering St. Lucie Units 1 and 2 accident analyses assume ground level releases, the plant vent stacks do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore are not within the scope of license renewal."

Page 2.1-4 of the LRA states, "The offsite dose analyses indicate that the radiological consequences of these design basis events, except for the Unit 2 FHA, represent a small fraction of the 10 CFR Part 100 limits. As a result, SSCs related to the prevention and/or mitigation of these design basis events do not meet the scoping criteria of 10 CFR

54.4(a)(1)(iii). This equipment will still be evaluated relative to the scoping criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3)."

However, the structural aspects of the vent stacks are not discussed in Section 2.4 of the LRA. The vent stack structures are not subject to an AMR, although the supports for the vent stacks are identified in Table 3.5-2 of the LRA as being subject to an AMR. The vent stacks for both units are shown on the enlarged site plot plan drawing 2998-G-059 (Figure 1.2-2 of UFSARs for both Units 1 and 2), at location G7 for Unit 1 and location G10 for Unit 2. The vent stack for Unit 1 is also shown in drawing 8770-G-067 at locations C11 through H11. These stacks are large structures with a height of about 140 feet and an outer diameter of about 6 feet. The vent stacks are attached to and supported by the shield building structure and sit on top of the penetration area of the RAB.

The staff questioned the applicant about whether the vent stacks should be included within the scope of license renewal and subject to an AMR for several reasons.

- The vent stacks are substantial structures in proximity to the shield buildings and sit directly on top of portions of the RABs. The shield and RABs are within the scope of license renewal and have safety-related intended functions. Failure of the vent stack could damage nearby buildings and components and render them unable to perform their safety-related intended functions.

- The vent stacks contain and support radiation monitors that are relied upon to function in the event of a waste gas accident. As described in Section 15.4.2-2 of the Unit 1 UFSAR, the high-radiation alarms from these monitors are a signal to manually close the control room ventilation intake dampers.

- Blockage of effluent flow from the vent stack as a result of a structural failure could prevent the SBVS from performing its in-scope intended function.

By letter dated November 7, 2002, the applicant responded to RAI 2.4.1-6 that structural failure of the vent stacks would not result in the failure of the containments and RABs for Units 1 and 2 to perform their safety-related intended functions. If the vent stacks were assumed to fall, they could potentially impact the walls of the containments or the walls and/or roofs of the RABs. These structures are constructed of cast-in-place, reinforced concrete with a thickness ranging from 2 to 4 feet. They are designed to resist high-energy missiles without spalling (Section 3.5 in the UFSARs for Units 1 and 2) which would bound the impact energy of a falling vent stack.

Although the vent stack radiation monitors are noted in Section 15.4.2-2 of the Unit 1 UFSAR, these monitors do not perform or support any system intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). In this section of the UFSAR, the applicant states that:

> Releases from the waste gas tank are exhausted by the auxiliary building main ventilation system through the plant vent. This exhaust is assumed to be released at ground level and to leak back into the auxiliary building.
>
> It is conservatively assumed that the control room immediately receives inleakage from the RAB.

The waste gas accident would result in a high radiation alarm from either local monitors or the plant vent.

The local monitors noted in this statement are the ones located in control room air conditioning. As described in Section 9.4.1 of the Unit 1 UFSAR and Section 12.3.4.2.3.2 of the Unit 2 UFSAR, safety-related isolation of control room air conditioning is provided by redundant radiation monitors located in each of the control room air conditioning air intakes. As described in Section 2.3.3.15 of the LRA, the control room air conditioning subsystems (and associated radiation monitors) for Units 1 and 2 are included in the scope of license renewal.

The staff considers the applicant's response to RAI 2.4.1-6 to have three relevant parts—(1) structural failure of the vent stack would not result in blockage of effluent flow, (2) no safety-related equipment is located nearby such that it could be damaged by the fall of the vent stack, and (3) the impact of a falling vent stack is bounded by the impact momentum of missiles analyzed in the UFSAR.

The staff agrees with the applicant's statement that structural failure of the vent stack would not result in blockage of effluent flow, on the basis of industry and plant-specific experience. The vent stacks are large steel cylinders mounted at a high elevation; a failure mode which completely blocks the effluent outlet is unlikely.

To confirm the second part of the applicant's response to RAI 2.4.1-6, the staff requested that the inspection team confirm that failure of the main plant stack or the fuel handling building vent stack would not damage safety-related equipment. As documented in Inspection Report 2002-07, dated November 27, 2002, the inspectors walked down the associated roof areas and reviewed drawings (for elevation 42 feet) of the RAB. The inspectors concluded that there is no safety-related equipment on the roof of the RAB that would be affected by failure of the main plant stack or the fuel handling building stack.

The staff considered the third part of the applicant's response to RAI 2.4.1-6. The missiles considered in the cited UFSAR analysis are not as massive as a plant vent stack. The staff therefore requested that the applicant justify the statement that the impact of high-energy missiles (as analyzed in Section 3.5 in the UFSARs for Units 1 and 2) would bound the impact energy of a falling vent stack. By letter dated November 27, 2002, the applicant supplemented its response to RAI 2.4.1-6 with the following information.

> An analysis has been performed that demonstrates a structural failure of a plant vent stack is enveloped by the high-energy missiles described in the UFSARs. The 135' tall plant vent stack weighs approximately 64,000 lbs. The impact energy of the bounding critical case missile is approximately 155,000 ft-lbs. The incremental impact energy of a fallen vent stack ranges from 2 ft-lbs at the base to approximately 96,000 ft-lbs at the top.

The staff finds the third part of the applicant's response to RAI 2.4.1-6 to be acceptable on the basis that the impact energies of a falling vent stack have been demonstrated to be less than the missile energies previously analyzed by the applicant.

On the basis that (1) the main plant vent stacks do not have an intended function meeting the criteria of 10 CFR 54.4(a) and (2) the failure of the vent stacks would not result in potential spatial interactions that could cause the failure of safety-related structures or components, the staff agrees with the applicant's conclusion that the main plant vent stacks for Units 1 and 2 should not be included within the scope of license renewal and are not subject to an AMR

The staff's review found that the SCs of the reactor containment shield buildings that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.1.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the reactor containment shield building structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.1.3 Reactor Containment Shield Building Interior Components

2.4.1.3.1 Summary of Technical Information in the Application

In Section 2.4.1.3 of the LRA, the applicant describes the interior SCs of the containment vessels and reactor containment shield buildings that are within the scope of license renewal and subject to an AMR. The interior SCs of the containment vessels and reactor containment shield buildings are further described in Section 3.8.3 of the UFSARs for St. Lucie Nuclear Plant, Units 1 and 2.

The interior structures of the containment vessels and reactor containment shield buildings consist of concrete and steel components. The major concrete internal components are the primary and secondary shield walls, the refueling cavity, the operating floor, and the enclosures around the pressurizer and steam generators. The major steel internal components are the RCS supports; the refueling cavity liner; steel framing; miscellaneous platforms; pipe whip restraints; and supports for cable trays, conduits, ventilation ducting, piping, and other components. The internal structures are supported on the concrete floor fill placed in the bottom of the steel containment vessel. The RCS is located within the compartments formed by the concrete fill floor, the primary and secondary shield walls, and the concrete enclosures around the steam generators and the pressurizer.

Concrete. The shield walls are thick, cylindrical reinforced concrete walls that enclose the reactor vessels and provide biological shielding and structural support. The shield walls also act as a missile barrier. The refueling cavity is a stainless- steel- lined, reinforced concrete structure that forms a pool above the reactor when it is filled with borated water for refueling.

All high-pressure equipment and high-energy RCS piping and components that could generate missiles as a result of a design-basis accident are surrounded by barriers. These barriers, principally the primary and secondary shield walls, prevent such missiles from damaging the containment vessel, piping penetrations, and the required ESF systems.

Concrete walls, floors, beams, equipment pads, and other miscellaneous concrete components are of conventional reinforced concrete design.

Steel. Reactor Cavity Sumps: The floors and walls of each unit's reactor cavity are lined with stainless steel. The floor is sloped to drain all leakage to the reactor cavity sump. The reactor cavity sump is located below the reactor cavity outside the primary shield wall.

Containment Sumps: The containment sumps are provided to collect water for recirculation through the shutdown cooling heat exchangers after a LOCA. The containment sumps are located below the lowest floor elevation inside the containment except for the reactor cavity and the reactor cavity sump. Vent openings in the secondary shield wall direct water into the containment sump. Drains from the containment sump to the reactor cavity sump prevent accumulation of water in the containment. Screens are provided for the containment sumps to prevent debris from entering the sumps and the ECCS.

Reactor Coolant System Supports: The RCS supports that are subject to an AMR include the reactor vessel supports, steam generator supports, pressurizer supports, and RCP supports. The RCS supports are designed to resist operating loads, pipe ruptures, and seismic loads.

The RCS support boundaries that are subject to an AMR include all structural support items between the RCS components and the containment concrete structure, up to and including integral attachments that are on RCS components.

Miscellaneous Steel and Component Supports: Miscellaneous and structural steel components are provided in each containment to allow access to the various elevations and areas for inspection and maintenance. The structural steel provides support for safety-related and non safety-related systems and components, including piping, ducts, miscellaneous equipment, electrical cable trays and conduit, instruments and tubing, electrical and instrumentation enclosures and racks, steel beams and columns, stairways, ladders, and attachments to concrete walls and liners.

2.4.1.3.2 Staff Evaluation

The staff reviewed Section 2.4.1.3 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the interior SCs of the containment vessels and reactor containment shield buildings that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.5-2 of the LRA to determine whether the applicant adequately identified the components of the interior SCs of the containment vessels and reactor containment shield buildings that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled the interior SCs of the containment vessels and reactor containment shield buildings that were not listed in Table 3.5-2 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Section 3.8.3 of the UFSARs for Units 1 and 2 and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.1.3 of the LRA.

During the review, the staff determined that additional information was needed to complete its evaluation of the interior components of the containment vessels and reactor shield building structure. In a letter dated July 1, 2002, the staff requested that the applicant justify the omission of insulation from the scope of license renewal and subject to an AMR (RAI 2.4.1-5). Thermal insulation is typically present on major components of the reactor, pipes, and valves; pipe and equipment component supports; and structural enclosures and panels used to shelter instruments and electrical equipment. No insulation material is shown in Table 3.5-2 of the LRA as within the scope of license renewal. The temperature control intended function provided by insulating materials is important for environmental qualification, as piping and components with degraded insulation will experience additional heat loads and condensation.

By letter dated October 3, 2002, the applicant responded that thermal insulation is not within the scope of license renewal because it does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). Environmental temperature qualification of in-containment components is maintained through temperature monitoring and the Units 1 and 2 technical specifications (Section 4.4, page 4.4-3 of the LRA). The insulation provides a negligible heat transfer effect with regard to containment heat loads following design-basis accidents. Additionally, no insulation is credited in the environmental qualification of individual components such as insulation boxes.

During the NRC scoping and screening inspection conducted the week of October 21-25, 2002, as documented in Inspection Report 2002-07 dated November 27, 2002, the staff confirmed that insulation is not credited for temperature control or for environmental qualification at Units 1 and 2. For example, the insulation used in the main control room envelope or the rooms cooled by the portion of the HVAC system for ECCS areas was not credited for temperature maintenance in SBO heatup analysis. Insulation used for protection of electrical panels in post-accident harsh environments also was not credited in any environmental qualification analyses.

On the basis that insulation does not perform or support any intended function meeting the criteria of 10 CFR 54.4(a), the staff finds the applicant's response to be acceptable. The staff agrees with the applicant that insulation described above should not be included in the scope of license renewal and is not subject to an AMR for Units 1 and 2.

The staff's review found that the interior SCs of the containment vessels and reactor shield buildings that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.1.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant appropriately identified the containment vessels and reactor containment shield buildings structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2 Other Structures

2.4.2.1 Component Cooling Water Areas

2.4.2.1.1 Summary of Technical Information in the Application

In Section 2.4.2.1 of the LRA, the applicant described the SCs of the component cooling water areas that are within the scope of license renewal and subject to an AMR. The component cooling water areas are further described in Section 9.2.2 and Appendix 9.5A of the UFSAR for Unit 1 and Section 3.4 of the UFSAR for Unit 2.

The Unit 1 and Unit 2 component cooling water areas house the safety-related component cooling water pumps and heat exchangers and are designed to seismic Category 1 requirements.

The Unit 1 component cooling water area is an outdoor area, exposed to the environment, with pumps and heat exchangers supported on concrete pedestals well above flood and wave run-up elevations. Steel missile barriers are provided over the pumps.

The Unit 2 component cooling water area consists of an enclosed concrete building. The component cooling water pumps and heat exchangers are housed in a rectangular reinforced concrete missile protection structure. The structure consists of a base mat, exterior walls, and a concrete roof slab, supported on the exterior walls and on reinforced concrete columns. The Unit 2 component cooling water system equipment susceptible to flood damage is protected by locating all safety-related components above the maximum expected water level and wave run-up during a probable maximum hurricane.

The applicant lists the SCs of the component cooling water areas subject to an AMR in LRA Table 3.5-3. They include structural steel framing, stairs, ladders, platforms, checkered plate, grating, component supports, pipe and component supports, non-safety-related pipe segments between class break and seismic anchor, Unit 1 missile barriers, Unit 2 missile protection doors, conduits, conduit supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, HVAC duct supports, tubing supports, passive components of the trolley hoists, reinforced concrete above groundwater (external surfaces of foundation slab and walls below grating, walls and roofs above grating), and reinforced concrete (equipment pedestals and internal surfaces of walls and foundation slabs below grating). The applicant also lists the following intended functions of these components in LRA Table 3.5-3.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide missile barriers
- provide fire barriers to retard spreading of a fire
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs
- provide flood protection barriers
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events

2.4.2.1.2 Staff Evaluation

The staff reviewed Section 2.4.2.1 of the LRA to determine whether the applicant adequately identified the SCs of the component cooling water areas that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in LRA Table 3.5-3 to determine whether the applicant adequately identified the SCs belonging to the component cooling water areas that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled the SCs of the component cooling water areas that were not listed in LRA Table 3.5-3 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Sections 3.3, 3.4, 3.5, and 9.2.2 and Appendices 3F and 9.5A of the UFSAR for Unit 1 and Section 3.4 of the UFSAR for Unit 2 and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.2.1 of the LRA.

During the review, the staff questioned the applicant's omission of the component cooling water area sump from Table 3.5-3 during a meeting with the applicant held on June 10 through 11,

2002. As documented in the meeting summary dated July 31, 2002, the applicant explained that the component cooling water area sump was actually a recess in the foundation slab that was scoped and screened as a yard structure in LRA Table 3.5-16 and, as such, is identified as a reinforced concrete pipe trench on page 3.5-93. This explanation is acceptable to the staff, as it explains that the sump is subject to an AMR.

The staff's review found that the SCs of the component cooling water areas that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.1.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the component cooling water areas structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.2 Condensate Polisher Building

2.4.2.2.1 Summary of Technical Information in the Application

In Section 2.4.2.2 of the LRA, the applicant identifies the SCs of the condensate polisher building that are within the scope of license renewal and subject to an AMR. This building is common to both St. Lucie Units 1 and 2. The fire protection areas of the condensate polisher building are described in Appendix 9.5A, Section 4.0, of the St. Lucie Unit 1 UFSAR.

The condensate polishing building is a reinforced concrete building shared in common by both Units 1 and 2. This building is within the scope of license renewal because it provides structural support and/or shelter to a fire hose station designated as Fire Zone 15A in the St. Lucie FP program and it contains FP equipment and components. The condensate polisher building has no other intended function and does not contain safety-related components.

The condensate polisher building structural component types that are subject to an AMR are listed in Table 3.5-4 of the LRA and include component supports (non-safety-related), pipe supports (non-safety-related), and reinforced concrete above ground water. The intended functions of these component types are also listed in Table 3.5-4 as structural support and/or shelter to components required for FP, ATWS, and/or SBO events.

2.4.2.2.2 Staff Evaluation

The staff reviewed Section 2.4.2.2 of the LRA and Appendix 9.5A and Section 4.0 of the UFSAR for Unit 1 to determine whether the SCs of the condensate polisher building within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff focused on SCs that were not identified as being subject to an AMR to determine whether any components were omitted.

The staff observed that the only information supplied for the condensate polisher building in Appendix 9.5A, Section 4.0, of the Unit 1 UFSAR as referenced by Section 2.4.2.2 of the LRA, is an identification of the FP areas in this building. A small amount of additional information is presented in Section 1.2-6, page 1.2-23, of the Unit 1 UFSAR and Section 1.2-4, page 1.2-14, of the Unit 2 UFSAR. The staff was unable to determine whether the SCs of the condensate polisher building within the scope of license renewal were appropriately identified by the applicant in Table 3.5-4 of the LRA. Therefore, during a meeting on June 10, 2002, the staff requested that the applicant provide more information about the condensate polisher building and the equipment housed within the building (RAI 2.4.2.2-1).

The applicant replied that the condensate polisher building contains no safety-related equipment. The applicant further stated that the condensate polisher building is within the scope of license renewal because a fire hose station and some FP equipment are located in the building. The staff requested that the NRC inspection team confirm these statements during the onsite scoping and screening inspection conducted October 21—25, 2002. As documented in Inspection Report 2002-07, dated November 27, 2002, the inspection included a walkdown of the condensate polisher building.

The inspection determined that the condensate polisher building was built after Unit 1 was initially licensed. The purpose of the structure is to house the condensate polisher system, which is not within the scope of license renewal. In addition, the building contains lighting, domestic water, ventilation, communication, crane, and FP systems. The applicant identified the FP system as being within the scope of license renewal in accordance with 10 CFR 55.4(a)(iii) for regulated events. Results of the inspection concluded that the applicant had appropriately identified the SCs that are within the scope of license renewal for the condensate polisher building.

The staff's review found that the SCs of the condensate polisher building that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.2.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the condensate polisher building structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.3 Condensate Storage Tank Enclosures

In Section 2.4.2.3 of the LRA, the applicant identifies the SCs of the CST enclosures that are within the scope of license renewal and subject to an AMR. The Unit 1 CST enclosure is described in Section 3.5.4.2, Appendix 3F, Section 4.3.5, and Appendix 9.5A of the Unit 1 UFSAR. The Unit 2 CST enclosure is described in Section 3.8.4.1.7 and Appendix 9.5A of the Unit 2 UFSAR.

2.4.2.3.1 Summary of Technical Information in the Application

The Unit 1 and Unit 2 CST enclosures are cylindrical reinforced concrete structures designed to seismic Category 1 requirements for the intended function of tornado missile protection.

The Unit 1 CST enclosure is contained in an open-roof structure enclosed by steel framing across the top supporting a steel grating security barrier. The structure is supported on a reinforced concrete base mat. This structure was designed to protect against horizontal missiles.

The Unit 2 CST enclosure is equipped with a precast concrete dome roof overlaid with reinforced concrete that protects the tank from both horizontal and vertical missiles. The structure is supported on a reinforced concrete base mat.

The steel CSTs are bolted to reinforced concrete ring wall pedestals that are supported on the base mats. The tank bottoms are supported on a Class 1 structural fill that is enclosed within the concrete ring walls.

The structure and component types of the CST enclosure subject to an AMR are listed in Table 3.5-5 of the LRA. They include structural steel framing (columns, beams, connections, etc.), stairs, ladders, platforms, handrails, checkered plate, grating, component supports (non-safety-related), safety-related pipe supports and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, conduits, conduit supports, electrical and instrument panel and enclosure supports, tubing supports, missile protection hood (Unit 2 only), and reinforced concrete above groundwater.

The intended functions of the SCs of the CST enclosure subject to an AMR are listed in Table 3.5-5 of the LRA and again below.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related SCs whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SCs
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events

2.4.2.3.2 Staff Evaluation

The staff reviewed Section 2.4.2.3 of the LRA; Section 3.5.4.2, Appendix 3F, Section 4.3.5 and Appendix 9.5A of the Unit 1 UFSAR; and Section 3.8.4.1.7 and Appendix 9.5A of the Unit 2 UFSAR to determine whether there is reasonable assurance that the CST enclosure structural components within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1). The staff also focused on components that were not identified as being subject to an AMR to determine whether any components were omitted.

During a meeting with the applicant on June 10, 2002, the staff referred to Section 2.4.2.3 of the LRA which states, "The steel CSTs are bolted to reinforced concrete ring wall pedestals that are supported on the base mats. The tank bottoms are supported on Class 1 structural fill that is enclosed within the concrete ring walls." However, bolts and base mats are not identified in Table 3.5-5 of the LRA that lists the CST enclosure SCs within the scope of license renewal.

As documented in the summary (dated July 31, 2002) of the June 10, 2002, meeting, the applicant responded that reinforcing steel and embedded steel are evaluated with the concrete components in which they are embedded. The base mats are concrete. The bolts and base mats are included in Table 3.5-5 of the LRA as part of the commodity group, "reinforced concrete above groundwater."

The staff finds the applicant's response acceptable, on the basis that it clarifies that the applicable components are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff's review found that the SCs of the CST enclosures that have intended functions meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.3.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the CST enclosures structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.4 Diesel Oil Equipment Enclosures

In Section 2.4.2.4 of the LRA, the applicant identifies the SCs of the diesel oil equipment enclosures that are within the scope of license renewal and subject to an AMR. This system is further described in Section 9.5.4 of the UFSARs for Units 1 and 2.

2.4.2.4.1 Summary of Technical Information in the Application

The Unit 1 diesel oil equipment enclosures consist of complete enclosures for the diesel oil transfer pumps and a partial enclosure for the diesel oil storage tanks. The diesel oil transfer pumps are protected from the environment and external missiles by reinforced concrete seismic Category 1 enclosures. The Unit 1 diesel oil storage tanks are located outdoors on concrete foundations surrounded by a reinforced concrete containment wall to contain the diesel oil in the event of overflow or rupture.

The Unit 2 diesel oil transfer pumps and diesel oil storage tanks are located within a fully enclosed reinforced concrete seismic Category 1 structure. The structure is divided into two distinct compartments by an interior reinforced concrete missile shield wall.

In Table 3.5-6 of the LRA, the applicant lists the following structure and component types of the diesel oil equipment enclosure subject to an AMR. They include stairs, ladders, platforms, handrails, checkered plate, grating, pipe and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, conduits, conduit supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, miscellaneous steel (Unit 2 missile barrier doors), diesel oil storage tank foundations, and reinforced concrete above ground water.

The SCs of the diesel oil equipment enclosures have the following intended functions as listed in Table 3.5-6 of the LRA.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components

- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related structures or components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide flood protection barrier
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events (Unit 2 enclosure for a Unit 1 SBO)

2.4.2.4.2 Staff Evaluation

The staff reviewed Section 2.4.2.4 of the LRA and Section 9.5.4 of the UFSAR for Units 1 and 2 to determine whether there is reasonable assurance that the SCs of the diesel oil equipment enclosures within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1). The staff also focused on SCs that were not identified as subject to an AMR to determine whether any SCs were omitted.

The staff's review found that the SCs of the diesel oil equipment enclosures that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.4.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the diesel oil equipment enclosures structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.5 Emergency Diesel Generator Buildings

In Section 2.4.2.5 of the LRA, the applicant identifies the SCs of the emergency diesel generator buildings that are within the scope of license renewal and subject to an AMR. The emergency diesel generator buildings are described in Sections 3.8.1.1.3, 3.8.1.7.4, 8.3, 9.4.7, and 9.5 of the Unit 1 UFSAR, and Sections 3.8.4.1.4, 8.3, 9.4.5, and 9.5 of the Unit 2 UFSAR.

2.4.2.5.1 Summary of Technical Information in the Application

Both the Unit 1 and the Unit 2 emergency diesel generator buildings are seismic Category 1 reinforced concrete structures, housing duplicate diesel generating units, each separated by an interior reinforced concrete wall. Each emergency diesel generator building consists of a base mat, exterior walls, one interior wall separating the units, and a concrete roof. Concrete pedestals on the base mat support the diesel generator sets. The emergency diesel generator buildings also house the components of the diesel generator subsystems, such as the diesel engine and air systems, fuel and lube oil systems, cooling water systems, and the diesel oil system.

The applicant lists the SCs of the emergency diesel generator building subject to an AMR in Table 3.5-7. They include stairs, ladders, platforms, checkered plate, grating, component supports (non-safety-related), safety-related pipe supports and component supports, non-safety-related pipe supports, conduits, conduit supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, tubing supports, miscellaneous steel, missile protection doors, missile protection exhaust hoods (Unit 2 only), exterior louvers (for ventilation and missile protection - Unit 1 only), trolley hoists (passive components), and reinforced concrete above ground water (slabs, walls, roofs, trenches).

Table 3.5-7 also lists the following intended functions of the SCs of the emergency diesel generator buildings.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related structures or components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide flood protection barriers
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events

2.4.2.5.2 Staff Evaluation

The staff reviewed Section 2.4.2.5 of the LRA; Sections 3.8.1.1.3, 3.8.1.7.4, 8.3, 9.4.7, and 9.5 of the Unit 1 UFSAR; and Sections 3.8.4.1.4, 8.3, 9.4.5, and 9.5 of the Unit 2 UFSAR to determine whether there is reasonable assurance that the SCs of the emergency diesel generator buildings have been adequately identified within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

In a meeting with the applicant that took place on June 10, 2002, the staff referred to Section 2.4.2.5 of the LRA, which states that the emergency diesel generator buildings are in the scope of license renewal, in part because they are flood protection barriers. In Table 3.5-7 of the LRA, the intended function of flood protection barriers is identified for (a) reinforced concrete above ground and (b) missile protection doors. The staff asked how these doors function for flood protection. Any special features of these doors that serve for flood protection, such as gaskets, should be listed in Table 3.5-7.

As documented in the summary (dated July 31, 2002) of the June 10, 2002 meeting, the applicant responded that all permanent door openings in the exterior walls of the emergency diesel generator building are constructed with swing-type doors for protection from rain, wind, and other atmospheric effects. The access doors do not have weather-stripping in all cases; however, the amount of leakage-induced flooding through these doors is not more adverse than that considered in the analysis presented in Section 3.1.3 of Chapter 9.5A of the UFSAR on the rupture of nonseismic Class 1 equipment (fire system piping).

As a followup to this issue, the staff asked the applicant to justify the omission of the emergency diesel building floor drains from the scope of license renewal by letter dated July 29, 2002 (RAI 2.2-2). This RAI referred, in part, to page 3.6F-7 of the Unit 2 UFSAR, which credits the floor drains in the internal flooding analysis for the Unit 2 diesel generator building.

By letter dated October 3, 2002, the applicant responded by presenting the results of a reevaluation of internal flooding of the diesel generator building that did not credit the availability of the floor drains. The applicant stated that the flood elevation resulting from a crack in the service water line would reach only a few inches above the floor level, even assuming a complete blockage of the floor drains. This analysis credits drainage through the opening under the doors in each room of the building. This flooding elevation is well below the elevation of the safety-related components in the diesel generator buildings. Accordingly, the Unit 2 emergency diesel generator building floor drains do not perform an intended function that satisfies the scoping criteria of 10 CFR 54.4(a).

During the AMP inspection, which ended on January 31, 2003, the inspection team verified the openings under the doors in the Unit 2 emergency diesel generator building. The inspectors questioned the size of the openings, and the applicant initiated activities to ensure the door clearances remain greater than the openings assumed in the emergency diesel generator building area drain evaluation. The staff's review of the inspection finding was Open Item 3.0.2.2-1.

Inspection Report 50-335/2003-03 and 50-389/2003, issued on March 7, 2003, is attached to this SER. The staff reviewed the inspection report findings and concluded that the identified corrective actions ensure that the emergency diesel generator building floor drains do not perform an intended function that would result in the failure of a safety-related component, and, therefore, the drains are not within the scope of license renewal. The staff considers Open Item 3.0.2.2-1 closed.

The staff finds that the SCs of the emergency diesel generator buildings that have intended functions meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.5.3 Conclusions

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the SCs of the emergency diesel generator buildings that are within the scope of license renewal as required by 10 CFR 54.4(a) and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.6 Fire-Rated Assemblies

In Section 2.4.2.6 of the LRA, the applicant identifies the SCs of the fire-rated assemblies that are within the scope of license renewal and subject to an AMR. The fire-rated assemblies are described in Appendix 9.5A and Sections 3.11 through 3.14 of the St. Lucie UFSARs for both units.

2.4.2.6.1 Summary of Technical Information in the Application

Fire- rated assemblies are required as part of the plant's FP program in accordance with 10 CFR 50.48. Fire- rated assemblies at St. Lucie Units 1 and 2 include fire barriers, fire doors, fire dampers, and penetration seals.

In Section 2.4.2.6 of the LRA, the applicant discusses the need for fire barriers to retard the spread of fire and states that fire-resistant panels (e.g., Thermo-lag, sheet metal/ceramic fiber) mounted on steel framing are used as fire barriers. Section 2.4.2.6 further references Table 3.5-8 of the LRA and Appendix 9.5A of the Unit 1 and 2 UFSARs, which state that barriers (e.g., wall, floors, ceiling) divide the plant into fire areas. In Table 3.5-8 of the LRA, the applicant notes that concrete and steel structural components that serve as fire barriers are addressed with each structure.

The applicant listed the fire- rated assembly SCs requiring an AMR in Table 3.5-8 as conduit caps, fire wrap (conduit and steel supports), conduit plugs, miscellaneous barriers (Thermo-lag panels, wrap, sprays, or troweled, ceramic and steel panels), fire doors (Appendix R barriers, airtight and watertight), flame impingement shields, fire sealed isolation joint, mechanical penetrations, cable tray penetrations, and radiant energy shields. The intended functions of these SCs are listed as pressure boundary, fire barrier, flood protection barrier, and boundary for safety-related ventilation.

2.4.2.6.2 Staff Evaluation

The staff reviewed Section 2.4.2.6 of the LRA and the associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the fire-rated assemblies that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff reviewed Table 3.5-8 of the LRA to determine whether the applicant appropriately identified the components belonging to the fire-rated assemblies that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the fire-rated assemblies that were not listed in Table 3.5-8 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Appendix 9.5A of the Unit 1 and 2 UFSARs and did not identify any system intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.2.6 of the applicant's LRA.

Fire barriers are provided to ensure that the function of one train of redundant equipment necessary to achieve and maintain safe shutdown conditions remains free of fire damage. Fire barriers provide a means of limiting fire travel by compartmentalization and containment. St. Lucie Units 1 and 2 fire barriers include walls, floors, ceilings, radiant energy shields, flame impingement shields, conduit fire wrap, and conduit plugs. Wall-type barriers and shields include concrete and masonry walls. Fire-resistant panels (e.g., Thermo-lag, sheet metal/ceramic fiber) mounted on steel framing are also used as fire barriers. Concrete and masonry walls, floors, and ceilings are evaluated with the specific structure in which they reside.

Fire door assemblies prevent the spread of fire through fire barrier passageways. Fire dampers are provided to prevent the spread of fire through ventilation penetrations. Fire dampers are evaluated with ventilation in Section 2.3.3.15 of the LRA.

Penetration seals are provided to maintain the integrity of fire barriers at barrier penetrations. The types of materials used for the various penetrations range from silicone gels for piping and HVAC penetrations to grouts for conduit and plumbing. Cable tray penetrations are sealed with Marinite board, ceramic fiber filler material, and a protective-fire retardant cable coating.

Although reference is made to structural steel for each structure discussed in the civil/structural sections of the LRA, no reference is made to the fire-resistive coverings on any structural steel in those structures. In a letter dated July 18, 2002, the applicant was asked to verify whether any structural steel fire barrier has been provided with fire-resistive coverings and if any barriers are identified, the applicant should justify why structural steel fire barriers provided with fire-resistive coverings are considered outside the scope of license renewal or are not subject to an AMR (RAI 2.4.2-1).

By letter dated October 3, 2002, the applicant responded that safety-related structures for St. Lucie Units 1 and 2 (e.g., RABs, fuel handling buildings, emergency diesel generator buildings, component cooling water areas, diesel oil equipment enclosures, etc.) are cast-in-place, reinforced concrete structures. The only steel-framed structure is the non-safety-related turbine building, which does not include fire-resistive coverings.

Structure steel is utilized in the construction of certain fire barriers. Note 1 on Table 3.5-8 refers to the structural steel framing listed in Tables 3.5-2 and 3.5-12 of the LRA. This steel framing provides the structural framework for the miscellaneous barriers listed in Table 3.5-8. Therefore, all structural steel fire barriers are included in the scope of license renewal and included in Table 3.5-8.

The staff finds the applicant's response to RAI 2.4.2-1 to be acceptable, on the basis that all structural steel fire barriers are included within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

The staff review found that the components of the fire-rated assemblies that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.6.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the fire- rated assembly structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.7 Fuel Handling Buildings

In Section 2.4.2.7 of the LRA, the applicant identifies the SCs of the fuel handling buildings that are within the scope of license renewal and subject to an AMR. The buildings are further described in Section 3.8.1.1.2 of the Unit 1 UFSAR and Section 3.8.4.1.3 of the Unit 2 UFSAR. This section of the LRA also contains the scoping and screening results for the fuel handling equipment and tools located in the fuel handling building. These tools and equipment are described in Section 2.4.2.8 of the LRA.

2.4.2.7.1 Summary of Technical Information in the Application

Each fuel handling building is a seismic Category 1 reinforced concrete structure. The fuel handling buildings each contain a spent fuel pool, a stainless- steel- lined, reinforced concrete tank structure that provides space for the storage of spent fuel, spent fuel casks, and miscellaneous items. The fuel handling buildings consist of concrete exterior walls with reinforced concrete interior walls. The floor and roof for the fuel handling buildings are of beam and girder construction supported by columns.

The applicant listed the structure and component types of the fuel handling building which require an AMR in Table 3.5-9 of the LRA. Table 3.5-9 also contains fuel handling equipment and tools located in the fuel handling building, which are described in Section 2.4.2.8 of the LRA. The list in Table 3.5-9 includes structural steel framing (columns, beams, connections, etc.), stairs, ladders, platforms, handrails, checkered plate, grating, component supports (non-safety-related), safety-related pipe supports and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, miscellaneous steel (radiation shielding, missile barriers, hatch frame covers, etc.), airtight doors (Unit 2 only), conduits, conduit supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, HVAC duct supports, HVAC louver (Unit 2 only), tubing supports, fuel transfer tube penetration sleeve, trolley hoists and cranes (passive components), spent fuel cask handling cranes (passive components), spent fuel handling machines (passive components), fuel pool gates, fuel transfer tubes and expansion bellows, pool liner plates, fuel handling tools (Unit 2 only), passive components of the fuel assembly upender (Unit 2 only), spent fuel storage racks, Boraflex (Unit 1 only), reinforced concrete above ground water, unreinforced concrete masonry block walls, cask removal L-shape hatches, airtight door seals, and weatherproofing.

The list of SCs subject to an AMR is specific for each unit because of differences in the CLB. That is, for a worst-case scenario, the Unit 1 FHA assumes a ground-level release, while the Unit 2 analysis credits the fuel handling building HVAC system, fuel handling building cranes and hoists, and proper functioning of the fuel handling equipment and tools for accident mitigation.

Table 3.5-9 of the LRA also lists the following intended functions for SCs.

- provide pressure boundary
- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide missile barriers
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide flood protection barriers
- provide a boundary for safety-related ventilation
- provide structural support and/or shelter to components required for FP, ATWS, or SBO events

2.4.2.7.2 Staff Evaluation

The staff reviewed Section 2.4.2.7 of the LRA, Section 3.8.1.1.2 of the Unit 1 UFSAR, and Section 3.8.4.1.3 of the Unit 2 UFSAR to determine whether the SCs of the fuel handling buildings within the scope of license renewal and subject to an AMR have been adequately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff also focused on components that were not identified as being subject to an AMR to determine whether any components were omitted.

During the review, the staff identified the omission of an intended function. By letter dated July 18, 2002, the staff requested that the applicant justify the omission of maintaining subcritical conditions as an intended function for spent fuel racks containing Boraflex and other fuel handling equipment and tools (RAI 2.4.2-3). Section 9.1 of the UFSARs for Units 1 and 2 states that the fuel storage racks are designed to maintain subcritical conditions in the fuel pool. However, Section 2.4.2.7 of the LRA does not list maintaining subcritical conditions as one of the attributes of the fuel handling building. In addition, none of the components or commodity groups listed in Table 3.5-9 of the LRA is credited with the intended function of maintaining subcritical conditions.

By letter dated October 3, 2002, the applicant responded that structural components of the fuel handling buildings that ensure the spent fuel remains subcritical (spent fuel racks and Boraflex) are identified in Table 3.5-9 of the LRA. These structural components have the intended function (with number 3), "Provide shelter/protection to safety-related components (including radiation shielding)." This intended function (also number 3 in Table 3.5-1 of the LRA) is supplemented to include maintaining subcritical conditions. The staff finds the applicant's response to be acceptable, on the basis that it identifies maintaining subcritical conditions as an intended function in accordance with the requirements of 10 CFR 54.21(a)(1).

In a letter dated July 18, 2002, the staff asked the applicant to justify the omission of the fuel handling building ventilation stacks from being subject to an AMR (RAI 2.4.2-4). The fuel handling building ventilation stacks are components of the fuel building ventilation systems but are also large structures attached to the exterior of the fuel buildings. Failure of these structures could damage nearby safety-related structures and components. In the LRA, the applicant states that these components are not within the scope of license renewal and not subject to an AMR. This concern is similar to the issue raised by the staff in RAI 2.4.1-6 for the main plant vent stacks in Section 2.4.1.2.2 of this SER.

The applicant responded to RAI 2.4.2-4 by letter dated November 27, 2002. The response stated that the failure of the fuel building vent stacks would not damage any safety-related structures or components as the impact energy of high-energy missiles analyzed in the UFSAR bounds the impact energy of a falling fuel building ventilation stack. The applicant justified this statement quantitatively with an analysis discussed in the response to RAI 2.4.1-6. The staff finds the applicant's response to RAI 2.4.2-4 to be acceptable, on the basis that (1) the fuel building vent stacks do not have an intended function meeting the criteria of 10 CFR 54.4(a), and (2) the failure of the fuel building vent stacks would not result in potential spatial interactions that could cause the failure of safety-related structures or components. The staff therefore agrees with the applicant's conclusion that the fuel building vent stacks for Units 1 and 2 do not need to be included within the scope of license renewal and are not subject to an AMR.

In a letter dated July 18, 2002, the staff asked the applicant to clarify if the Unit 1 fuel pool bulkhead monorail is included in Table 3.5-9 of the LRA as a component of the component group "trolley hoists and cranes" (RAI 2.4.2-5). By letter dated October 3, 2002, the applicant stated that the Unit 1 fuel pool bulkhead monorail is in the component group "trolley hoists and cranes" listed in Table 3.5-9. The staff finds this response acceptable, on the basis that it clarifies that these components are subject to an AMR.

The staff's review found that the SCs of fuel handling buildings that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.7.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the fuel handling building structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.8 Fuel Handling Equipment

In the LRA, fuel handling equipment is evaluated with the structure where it is located. Section 2.4.2.8 of the LRA provides a brief technical description of the fuel handling equipment for Units 1 and 2 but refers to Sections 2.4.1 and 2.4.2.7 of the LRA, containments and fuel handling buildings, respectively, for identification of specific fuel handling equipment components that are within the scope of license renewal and subject to an AMR. The fuel handling equipment is described in Section 9.1 of the UFSARs for Units 1 and 2.

2.4.2.8.1 Summary of Technical Information in the Application

Fuel handling equipment is an integrated system of equipment for refueling the reactor that provides for handling and storage of fuel assemblies from receipt of new fuel to shipping of spent fuel. The UFSARs state that this equipment is designed to remove and install fuel assemblies at each operating location in the core; safely handle and store fuel assemblies and control element assemblies; safely remove, replace, and store reactor internals; and minimize the probability of malfunction or operator-initiated actions that could cause fuel damage and potential fission product release or reduction of shielding water coverage.

The major fuel handling equipment includes, the reactor cavity seal rings, the manipulator cranes, the fuel transfer system, the spent fuel bridge cranes, the fuel handling tools, and the spent fuel cask crane. The fuel handling equipment is located in the containment or in the fuel handling buildings.

As identified by the applicant in Table 3.5-2 of the LRA, each containment houses and supports fuel handling equipment required for plant refueling. Components that are in the scope of license renewal and subject to an AMR include the refueling machine; the fuel transfer system (Unit 2 only); passive components of the polar crane, the telescoping jib crane, and other cranes and hoists; the reactor cavity seal rings; and one end of the fuel transfer tube including penetration sleeves, bellows, flange supports, and flexible membranes (in the annulus).

As identified by the applicant in Table 3.5-9 of the LRA, the fuel handling building contains the following fuel handling equipment within the scope of license renewal and subject to an AMR. This equipment includes the other end of the fuel transfer tube, fuel handling tools (Unit 2 only), and passive components of the spent fuel handling machines, the spent fuel cask crane, the trolley hoists and cranes, and the upender (Unit 2 only).

Some of the components identified above are designated as applying to Unit 2 only. As discussed in Section 2.1.1.2 of the LRA, the radiological consequences of the Unit 1 design-basis FHA are a small fraction of the 10 CFR 100 offsite dose limits. Section 15.4.1 of the Unit 1 UFSAR states that the system is not relied on or credited in the safety analyses for FHAs.

Therefore, these Unit 1 fuel handling components do not meet the scoping criteria of 10 CFR 54.4(a)(1)(iii) and, as such, are not within the scope of license renewal.

In Tables 3.5-2 and 3.5-9 of the LRA, the applicant identified the intended functions for fuel handling equipment components subject to an AMR as pressure boundary, structural support, and shelter/protection (including radiation shielding).

2.4.2.8.2 Staff Evaluation

The staff reviewed Section 2.4.2.8 of the LRA and Section 9.1 of the UFSAR for both St. Lucie units to determine whether there is reasonable assurance that the fuel handling equipment within the scope of license renewal and subject to an AMR has been adequately identified in accordance with 10 CFR 54.4 and 54.21(a)(1), respectively.

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff review of the LRA did not identify any omissions of structures, systems, or components that should be within the scope of license renewal and subject to an AMR. The staff review confirmed that equipment such as the cranes and hoists associated with handling fuel and other heavy loads in the vicinity of the spent fuel pool, new fuel storage racks, and reactor were in the scope of license review and subject to an AMR.

By letter dated July 18, 2002, the staff requested that the applicant provide specific information concerning the intended functions of the fuel storage racks. Specifically, the staff asked the applicant to justify not listing the maintenance of subcritical conditions as an intended function for any of the components of the fuel handling building in Table 3.5-9 of the LRA (RAI 2.3-1).

By letter dated October 3, 2002, the applicant responded that the structural components of the fuel handling buildings that ensure spent fuel remains subcritical (spent fuel racks and Boraflex) are identified in Table 3.5-9 of the LRA. In Table 3.5-9, these structural components are identified as performing intended function number 3, "Provide shelter/protection to safety-related components (including radiation shielding)." This intended function includes maintaining subcritical conditions.

The applicant's response clarified that the term "protection" in the definition of intended function, as noted above, includes maintenance of subcritical conditions. The staff's review confirmed that the applicant did identify structural components whose intended function is maintaining subcriticality, such as the Boraflex inserts used in the Unit 1 spent fuel pool, and that the intended function was cited for these components. The staff therefore finds the applicant's response to be acceptable, because the appropriate components and their intended functions are identified in accordance with 10 CFR 54.21(a)(1).

The staff's review found that the components of the fuel handling equipment that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.8.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the fuel handling equipment structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.9 Intake, Discharge, and Emergency Cooling Canals

In Section 2.4.2.9 of the LRA, the applicant identifies the SCs of the intake, discharge, and emergency cooling canals which are within the scope of license renewal and subject to an AMR. The intake, discharge, and emergency cooling canals are further described in Section 2.4.9 of the Unit 1 UFSAR and Section 2.4.9 of the Unit 2 UFSAR.

2.4.2.9.1 Summary of Technical Information in the Application

The intake, discharge, and emergency cooling canals provide redundant sources of cooling water to the plant heat sink for plant shutdown. The emergency cooling canal and the intake canal in the area of the intake structure have the intended function of providing a safety-related UHS that is designed to withstand design-basis seismic, tornado, and hurricane conditions. The discharge canal and most of the intake canal are not in the scope of license renewal because they do not perform a license renewal intended function.

The intake canal takes water directly from the Atlantic Ocean through underwater intake water pipes that run under the beach and terminate at the intake canal headwalls. In the unlikely event of blockage of the intake canal or pipes, emergency cooling water is taken from Big Mud Creek through the emergency cooling canal. The UHS dam (described in Section 2.4.2.14 of the LRA) separates the waters of Big Mud Creek from the intake canal during normal operation and provides a safety-related source of cooling water through valved openings if the ocean intake becomes unavailable. Big Mud Creek is connected to the Atlantic Ocean through the Indian River tidal lagoon. Regardless of the source, cooling water is discharged into the discharge canal and then flows to the Atlantic Ocean through discharge pipes.

The emergency cooling canal is seismic Category 1 in the area of the intake structure. Erosion protection in the area of the intake structure is provided by a concrete retaining wall and concrete embankments. The intake and discharge canal headwalls are reinforced concrete structures. The intake canal headwalls provide the termination point for the intake pipes from the Atlantic Ocean. The discharge canal headwalls provide the origination point for the discharge pipes to the Atlantic Ocean.

The applicant lists the SCs of the intake, discharge, and emergency cooling canals subject to an AMR in Table 3.5-10 of the LRA. They include concrete erosion protection (concrete paving and grout-filled fabric) and earthen canal dikes.

In Table 3.5-10 of the LRA, the applicant identifies the intended functions of SCs of the emergency cooling canal and the portion of the intake canal between the emergency cooling canal and the intake structure subject to an AMR as provide a source of cooling water for plant shutdown and provide structural support and/or shelter to components required for FP, ATWS, or SBO events.

2.4.2.9.2 Staff Evaluation

The staff reviewed Section 2.4.2.9 of the LRA and associated license renewal boundary drawings to determine whether there is reasonable assurance that the applicant appropriately identified the SCs of the intake, discharge, and emergency cooling canals that are within the scope of license renewal in accordance with 10 CFR 54.4(a). The staff then reviewed the AMR results provided in Table 3.5-10 of the LRA to determine whether the applicant appropriately identified the components of the intake, discharge, and emergency cooling canals that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff sampled those components of the intake, discharge, and emergency cooling canals that were not listed in Table 3.5-10 to verify that the applicant properly identified the components that meet the above requirements. The staff also reviewed Sections 3.8.1.1.5, 3.8.1.7.5, and 9.2.7 of the Unit 1 UFSAR and Section 9.2.5 of the Unit 2 UFSAR and did not identify any intended functions meeting the scoping criteria in 10 CFR 54.4(a) that were omitted from Section 2.4.2.9 of the LRA.

The staff confirmed that failure of the portion of the intake and discharge canals that was not in the scope of license review would not result in loss of the UHS cooling function. Section 9.2.7 of the Unit 1 UFSAR states that the intake canal is a seismically capable structure that will remain upright during and subsequent to a DBE. Appendix 2G of the UFSAR for Unit 1 provides an analysis of the stability of the underlying soils, and the test results provided in Supplement Number 2 to Appendix 2G verify that the intake canal sands are stable and will not liquefy in the event of an earthquake. Therefore, the intake structure cannot be blocked by a flow or slide of the intake canal sands.

The discharge from the ICW system flows through two parallel trains. In addition to the direct outlet to the discharge canal, each train has an alternate standpipe outlet. In the event that the discharge canal becomes unavailable, these elevated release points provide a reliable path for the discharge flow.

The staff's review determined that the structural components of the intake, discharge, and emergency cooling canal that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.9.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the the intake, discharge, and emergency cooling canal structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.10 Intake Structures

In Section 2.4.2.10 of the LRA, the applicant identifies the SCs of the intake structures that are within the scope of license renewal and subject to an AMR. The intake structures are further described in Sections 2.4.8 and 3.8.1.1.4 of the Unit 1 UFSAR and Section 3.8.4.1.5 of the Unit 2 UFSAR.

2.4.2.10.1 Summary of Technical Information in the Application

The intake structures are seismic Category 1 reinforced concrete structures containing the circulating water and ICW pumps. Each intake structure consists of a base mat, exterior walls braced internally to the bay walls, and an operating deck. Water centers each intake structure through four submerged openings and passes through the stationary and traveling screens before entering the rear of the intake structure, where the pumps are located.

The applicant listed the structure and component types of the intake structures requiring an AMR in Table 3.5-11 of the LRA as structural steel framing (columns, beams, connections, etc.), component supports (non-safety-related), safety-related pipe and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, miscellaneous steel (i.e., missile barriers, hatch frame covers, etc.), conduits, conduit supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, tubing supports, cranes (passive components), reinforced concrete (slabs, walls, roofs), reinforced concrete (pump pedestals), retaining walls, conduits (nonmetallic), intake level recorders, pvc pipe, and weatherproofing.

The applicant also identified the following intended functions of the SCs of the intake structures

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide a source of cooling water for plant shutdown
- provide missile barriers
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide structural support and/or shelter to components required for FP, ATWS, or SBO events

2.4.2.10.2 Staff Evaluation

The staff reviewed Section 2.4.2.10 of the LRA, Sections 2.4.8 and 3.8.1.1.4 of the Unit 1 UFSAR, and Section 3.8.4.1.5 of the Unit 2 UFSAR to determine whether the SCs of the intake structures within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively. The staff also focused on the SCs that were not identified as being subject to an AMR to determine whether any components were omitted.

In a meeting dated June 10, 2002, the staff requested that the applicant explain why flood protection is not required, although Section 3.8.1.1.4 of the Unit 1 UFSAR states, "The structure is designed to withstand seismic, tornado, missile and hurricane loadings and flooding." Flood protection is not listed in Section 2.4.2.10 of the LRA as one of the attributes of the intake structures. In addition, none of the component types listed in Table 3.5-11 of the LRA is credited with the intended function of flood protection.

The applicant responded that the information requested by the staff is contained in Section 3.4.4 of the Unit 1 UFSAR. Flood protection is provided to the intake structure by locating the ICW pump motors above elevation 22 feet. As discussed in Sections 2.4.5.6 and 2.4.5.7 of the Unit 1 UFSAR, additional flood protection beyond what is provided by the elevations of the openings of the safety-related structures is not required to protect any of the safety-related structures from wave runup or wind-driven rain, even during a probable maximum hurricane.

The staff finds the applicant's justification for the omission of the flood protection intended function to be acceptable, as the safety-related components in the intake structure are located above the anticipated maximum flood level.

The staff's review found that the SCs of the intake structures that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.10.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the intake structures structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.11 Reactor Auxiliary Buildings

In Section 2.4.2.11 of the LRA, the applicant identifies the SCs of the RABs that are within the scope of license renewal and subject to an AMR. The RABs are further described in Sections 3.8.1.1.1 of the Unit 1 UFSAR and 3.8.4.1.2 of the Unit 2 UFSAR.

2.4.2.11.1 Summary of Technical Information in the Application

The RABs are seismic Category 1 reinforced concrete structures with concrete exterior walls. The interior floors are beam and girder construction supported by reinforced concrete columns. All interior walls are either solid reinforced concrete block or reinforced concrete. Equipment located in the basement is supported by reinforced concrete piers that are tied to the base mat.

The applicant listed the structures and component types of the RABs requiring an AMR in Table 3.5-12 of the LRA. They include structural steel framing (columns, beams, connections, etc.), stairs, ladders, platforms, handrails, checkered plate, grating, component supports (non-safety-related), safety-related pipe and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, miscellaneous steel (radiation shielding, missile barriers, hatch frame covers, etc.), missile protection doors, watertight doors, airtight doors, conduits and cable trays, conduit and cable tray supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, HVAC duct supports, tubing supports, HVAC louvers, pipe whip restraints, trolleys and hoists (passive components), reinforced concrete above ground water, reinforced concrete below ground water (exterior), reinforced concrete below ground water (interior), reinforced concrete masonry block walls, unreinforced concrete masonry block walls, airtight door seals, watertight door seals, and weatherproofing.

In Table 3.5-12 of the LRA, the applicant also identified the following intended functions of the structure and component types of the RABs.

- provide pressure boundary (Halon for Unit 1 cable spreading room)
- provide structural support to safety-related components

- provide shelter/protection to safety-related components (including radiation shielding)
- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures and components
- provide flood protection barriers
- provide a boundary for safety-related ventilation
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO
- provide pipe whip restraint and/or jet impingement protection

2.4.2.11.2 Staff Evaluation

The staff reviewed Section 2.4.2.11 of the LRA, Section 3.8.1.1.1 of the Unit 1 UFSAR, and Section 3.8.4.1.2 of the Unit 2 UFSAR to determine whether the SCs of the RABs within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4 and 54.21(a)(1), respectively. The staff also focused on SCs that were not identified as being subject to an AMR to determine whether any components were omitted.

In a meeting on June 10, 2002, the staff requested that the applicant identify the table of the LRA where the stop log components are listed or justify their omission from the scope of license renewal. Stop logs are used to protect the RAB openings against floods and high winds. Section 3.4 of the Unit 2 UFSAR describes stop logs in the following manner.

> These aluminum stop logs would be stacked to Elevation 22.0 feet and secured with bolts ... The stop logs are stored onsite in a manner that reserves their readiness for use. When a hurricane watch is posted for the plant, the stop logs are removed from storage and prepared for installation; with actual installation occurring when the hurricane warning is posted for the plant.

However, Table 3.5-12 of the LRA does not list the stop log components as within the scope of license renewal and subject to an AMR.

The applicant explained that the information requested by the staff is located in Section 3.4 of the Unit 2 UFSAR on page 3.4-1. Based upon the probable maximum flood high-water level, wave-runup level, and plant island elevation, installation of flood protection stop logs at entrances whose minimum elevation is at least 19.5 feet is not deemed necessary. Additional wave runup protection is provided to the entrances of the RAB by stop logs installed to a height of 22 feet. Therefore, stop logs are considered not within the scope of license renewal. Stop logs are not used at Unit 1.

The staff finds the applicant's explanation to be acceptable, on the basis that it clarifies that the stop logs are an additional precaution taken by the applicant to protect against flooding and high waves, but the stop logs are not credited in the CLB for Unit 2.

The staff's review found that the SCs of the RABs that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.11.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the RAB structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.12 Steam Trestle Areas

In Section 2.4.2.12 of the LRA, the applicant identifies the SCs of the steam trestle areas that are within the scope of license renewal and subject to an AMR. The steam trestle areas are further described in Appendix 3C of the Unit 1 UFSAR and Section 3.8.4.1.9 of the UFSAR for St. Lucie Unit 2.

2.4.2.12.1 Summary of Technical Information in the Application

Each steam trestle area consists of two braced steel tower structures that contain safety-related components from the main steam, feedwater, and auxiliary feedwater systems. There are two separate trestle compartments per unit, located between each unit's containment and turbine buildings.

The applicant listed the SCs of the steam trestle area requiring an AMR in Table 3.5-13 of the LRA as structural steel framing (columns, beams, connections, etc.), stairs, ladders, platforms, handrails, checkered plate, non-safety-related component supports, safety-related pipe and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, miscellaneous steel (missile barriers, steel grating, etc.), conduits and cable trays, conduit and cable tray supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, tubing supports, reinforced concrete above ground water, reinforced concrete below ground water (exterior), and pipe whip restraints.

The applicant also identified the following intended functions of the SCs of the steam trestle areas in Table 3.5-13 of the LRA.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide fire barriers to retard spreading of a fire
- provide missile barriers
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO event
- provide pipe whip restraint and/or jet impingement protection

2.4.2.12.2 Staff Evaluation

The staff reviewed Section 2.4.2.12 of the LRA, Appendix 3C of the Unit 1 UFSAR, and Section 3.8.4.1.9 of the Unit 2 UFSAR to determine whether the SCs of the steam trestle areas within the scope of license renewal and subject to an AMR have been adequately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

In a meeting on June 10, 2002, the staff discussed the steam trestle area with the applicant. The staff referred to Appendix 3C of the UFSAR for Unit 1, which states, "The only other safety-related components in the area are the three auxiliary feedwater pumps and motors which are located under the trestles." On page 3C-4 it is stated that "There is no danger that a rupture of a steam line or feedwater line could cause a loss of function of more than one auxiliary pump due to flooding. Each of the three pumps are provided with a flood wall around them to Elevation 22 feet."

A list of steam trestle area structural components subject to an AMR and their intended functions is provided in Table 3.5-13 of the LRA. In that table, the component type "reinforced concrete above and below groundwater" is listed along with its intended functions. However, flood protection is not included as an intended function for that component or for any of the components listed in Table 3.5-13. The applicant was therefore asked to justify the omission of the flood protection intended function.

As documented in the meeting summary dated July 31, 2002, the applicant responded that the information requested by the staff is contained in Unit 1 UFSAR Section 3.2.2 on pages 3.2-4 to 2.3-10. The steam trestle areas are not safety-related structures and are not designed against flooding. However, components located in the steam trestle areas are required to be positioned at sufficient elevations to preclude flooding. The staff finds the applicant's response to be acceptable, on the basis that it explains that flood prevention is provided by positioning of the components in the steam trestle area and not by mitigative structures such as walls or curbs.

The staff's review found that the structural components of the steam trestle areas that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.12.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified steam trestle area structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.13 Turbine Buildings

In Section 2.4.2.13 of the LRA, the applicant identifies the SCs of the turbine buildings that are within the scope of license renewal and subject to an AMR. The turbine buildings are further described in Section 3.8.4.1 of the UFSAR for Unit 1 and Section 3.8.4.1.12 of the UFSAR for Unit 2.

2.4.2.13.1 Summary of Technical Information in the Application

The turbine buildings are primarily open steel frame structures, rectangular in shape, and built on reinforced concrete mat foundations. The operating deck of each turbine building supports a gantry crane. The turbine generator units are supported on separate concrete pedestals. The operating decks and intermediate mezzanine levels are concrete slabs.

The turbine buildings are not designed to seismic Category 1 requirements. However, both turbine buildings were seismically analyzed and found to maintain their structural integrity for the seismic loading condition. The only safety-related components in the Unit 1 turbine building are two safety-related valve motors for the isolation valves on the discharge of the feedwater pumps and associated safety-related power. There are no safety-related components in the Unit 2 turbine building. Both turbine buildings have safety-related piping buried beneath the ground floor slab.

The applicant listed the structure and component types of the turbine buildings requiring an AMR in Table 3.5-14 of the LRA as structural steel framing (columns, beams, connections, etc.), non-safety-related component supports, non-safety-related pipe segments between the class break and the seismic anchor, non-safety-related pipe supports (including the pipe hangers that indirectly support the Unit 1 safety-related main feedwater isolation valve motors), conduits and cable trays, conduit and cable tray supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, tubing supports, gantry cranes (passive components), turbine generator casings (covers), and reinforced concrete above ground water.

The applicant also identified the following intended functions of the SCs of the turbine buildings in Table 3.5-14 of the LRA.

- provide structural support to safety-related components (Unit 1 only)
- provide shelter/protection to safety-related components (Unit 1 only)
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide missile barriers
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO

2.4.2.13.2 Staff Evaluation

The staff reviewed Section 2.4.13.1 of the LRA, Section 3.8.4.1 of the Unit 1 UFSAR, and Section 3.8.4.1.12 of the Unit 2 UFSAR to determine whether there is reasonable assurance that the SCs of the turbine buildings within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff also focused on SCs that were not identified as being subject to an AMR to determine whether any components were omitted.

In a meeting with the applicant on June 10, 2002, the staff referred to Section 2.4.2.13 of the LRA that states "Both Turbine Buildings have safety-related piping buried beneath the ground floor slab." However, the safety-related piping buried beneath the ground floor slab is not included in Table 3.5-14 of the LRA. The staff requested that the applicant justify the omission from Table 3.5-14 of buried safety-related piping.

As documented in the meeting summary dated July 31, 2002, the applicant responded that this information is contained in Table 3.4-3 for the auxiliary feedwater and condensate system on page 3.4-16 of the LRA. The component group piping/fittings for stainless steel material is exposed to buried and embedded/encased environments. Note 1 reads, "Condensate storage tank cross-connect piping is susceptible to wetting." Note 2 reads, "Unit 1 auxiliary feedwater pump suction and recirculation piping is buried in sand beneath the Turbine Building and is not susceptible to wetting. Unit 2 auxiliary feedwater pump suction and recirculation piping is embedded/encased in concrete."

The staff found the applicant's explanation to be acceptable, on the basis that it clarifies that the piping buried beneath the turbine building is subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The staff's review found that the SCs of the turbine buildings that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.13.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the turbine building structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.14 Ultimate Heat Sink Dam

Section 2.4.2.14 of the LRA identifies the components of the UHS dam structure that are within the scope of license renewal and subject to an AMR. The ultimate heat sink dam is described in Sections 3.8.1.1.5, 3.8.1.7.5, and 9.2.7 of the Unit 1 UFSAR and Section 9.2.5 of the Unit 2 UFSAR.

2.4.2.14.1 Summary of Technical Information in the Application

The UHS dam has the intended function of providing a safety-related secondary source of cooling water to the UHS for Units 1 and 2. The UHS dam is a seismic Category 1 reinforced concrete retaining wall that extends across the emergency cooling canal. The UHS dam separates the waters of Big Mud Creek from the intake canal during normal operation and provides a safety-related source of cooling water through valved openings in the unlikely event that the ocean intake becomes unavailable. The primary source of UHS water is the ocean intake structure and intake canal. Big Mud Creek is connected to the Atlantic Ocean through the Indian River tidal lagoon. Water from Big Mud Creek flows through the dam in two parallel 137-cm (54-inch) pipes with pneumatically operated butterfly valves that are normally closed and spring open upon interruption of the air supply. The mechanical components contained in the UHS dam are included in the mechanical screening described in Section 2.3.3.5.

The main structure of the UHS dam consists of the concrete barrier wall, the perpendicular concrete buttresses, the concrete mat foundation, and the equipment rooms.

The ultimate heat sink dam is in the scope of license renewal because it provides structural support to safety-related components, shelter/protection to safety-related components, missile barriers, structural support to non-safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components.

Based on the intended functions previously identified, the applicant listed in Table 3.5-15 the UHS dam components subject to an AMR. They include pipe and component supports, miscellaneous steel, stairs, ladders, platforms, handrails, checkered plates, grating, conduit and cable trays, conduit and cable tray supports, electrical and instrument panel and enclosures, electrical and instrument panels and enclosure supports, tubing supports, non safety related pipe segments between class break and seismic anchor, steel sheet piling, and reinforced concrete. In that table, the applicant identified the intended functions for UHS dam components subject to an AMR as shelter/protection, missile barriers, and structural support.

2.4.2.14.2 Staff Evaluation

The staff reviewed Section 2.4.2.14 of the LRA, and Sections 3.8.1.1.5, 3.8.1.7.5, and 9.2.7 of the Unit 1 UFSAR, and Section 9.2.5 of the Unit 2 UFSAR to determine whether there is reasonable assurance that the structural components of the UHS dam within the scope of license renewal and subject to an AMR have been appropriately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

The staff's review found that the structural components of the UHS dam that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.14.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the UHS dam structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2.15 Yard Structures

In Section 2.4.2.15 of the LRA, the applicant identifies the components of the yard structures that are within the scope of license renewal and subject to an AMR. The yard structures are further described in Sections 2.4.5.3.2 and 8.3.1.1.9 of the Unit 1 UFSAR.

2.4.2.15.1 Summary of Technical Information in the Application

Yard structures include concrete foundations, concrete pipe trenches, concrete duct banks, electrical manholes, and the discharge canal nose wave protection. Steel support structures associated with these concrete structures are also included.

The applicant listed the SCs of the yard structures requiring an AMR in Table 3.5-16 of the LRA as component supports (non-safety-related), safety-related pipe supports and component supports, non-safety-related pipe supports, non-safety-related pipe segments between class break and seismic anchor, conduits and cable trays, conduit and cable tray supports, electrical and instrument panels and enclosures, electrical and instrument panel and enclosure supports, tubing supports, steel missile shield for diesel oil pipe (Unit 2 only), discharge canal nose wave protection (sheet piling), foundations (fire pumps, pipe supports, city water tanks, refueling water tanks, and Unit 2 primary water tank), concrete missile shield for diesel oil pipe, discharge canal nose wave protection (concrete cap), electrical duct banks and manholes, and reinforced concrete pipe trenches.

In Table 3.5-15 of the LRA, the applicant also identified the following intended functions of the yard structures.

- provide structural support to safety-related components
- provide shelter/protection to safety-related components
- provide missile barriers
- provide structural support to non safety-related components whose failure could prevent satisfactory accomplishment of the intended functions of safety-related structures or components
- provide flood protection barriers
- provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events

2.4.2.15.2 Staff Evaluation

The staff reviewed Section 2.4.2.15 of the LRA and Sections 2.4.5.3.2 and 8.3.1.1.9 of the Unit 1 UFSAR to determine whether the SCs of the yard structures within the scope of license renewal and subject to an AMR have been adequately identified in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The yard sump is highlighted on license renewal boundary drawing 2-FP-01 (at locations H4, H5). However, the yard sump is not listed in Table 3.5-16 of the LRA as being subject to an AMR. In a meeting conducted June 10—11, 2002, the staff requested that the applicant identify the yard sump in the applicable table of the LRA or justify its exclusion from the scope of license renewal and being subject to an AMR.

As documented in the meeting summary dated July 31, 2002, the applicant responded that the information requested by the staff (and noted above) is contained in Table 3.5-16 of the LRA (page 3.5-93). The yard sump is described as a recess in the foundation slab that is identified as a reinforced concrete pipe trench. The staff finds the applicant's response to be acceptable, as it clarifies that the yard sump is within the scope of license renewal and subject to an AMR.

The staff's review found that the SCs of the yard structures that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.4.2.15.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the yard structure structural components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical and I&C Systems

In Section 2.5, "Scoping and Screening Results—Electrical and Instrumentation and Controls (I&C) Systems," of the LRA, the applicant identifies electrical and I&C systems and component commodity groups subject to an AMR. The staff reviewed this section of the LRA to determine that all electrical/I&C systems and component commodity groups that should be within scope of Part 54 have been identified pursuant to the requirements of 10 CFR 54.4(a) and that, from these identified systems and component commodity groups, all electrical/I&C component commodity groups that should be subject to an AMR have been identified pursuant to the requirements of 10 CFR Part 54.21(a)(1).

2.5.1 Summary of Technical Information in the Application

2.5.1.1 Plant-Level Scoping Results

St. Lucie Nuclear Plant's IPA methodology consists of scoping, screening, and AMRs. If a system, in whole or in part, meets one or more of the license renewal scoping criteria, the system is considered to be within the scope of license renewal.

2.5.1.1.1 Out-of-Scope Electrical, I&C, and Mechanical Systems

The electrical/I&C systems (identified in Table 2.2-3 of the LRA), and thus their associated component commodity groups, determined to be out of scope include computer process and reactivity, generation and distribution (which includes main, auxiliary, and startup transformers and the switchyard), loose parts monitoring, meteorological monitoring, reactor regulating, and seismic monitoring systems. The mechanical systems (identified in Table 2.2-1 of the LRA), and thus their associated electrical/I&C component commodity groups, determined to be out of scope include air blower, blowdown cooling, blowdown waste management, cathodic protection, chemical feed, circulating water, condensate polishing, condensate recovery, containment airborne radioactivity removal (Unit 1 only), demineralized water, extraction steam, heater drains and vents, hypochlorite, meteorological monitoring, miscellaneous drains, neutralization basin, processed blowdown, security, sluice water, steam generator blowdown treatment facility—demineralization, steam generator blowdown treatment facility—radiation monitoring, steam generator blowdown treatment facility—spent resin, turbine lube oil, water treatment plant and Ecolochem facility, and wet lay-up.

2.5.1.1.2 In-Scope Electrical, I&C, and Mechanical Systems

The electrical systems (identified in Table 2.2-3 of the LRA), and thus their associated component commodity groups, found to be in scope include 120/208 V electrical, 120 V Vital AC, 125 V DC, 4.16 kV electrical, 480 V electrical, 6.9 kV electrical, communications, containment electrical penetrations (which include conductor, nonmetallic, and nonpressure boundary portions), data acquisition remote terminal unit, miscellaneous (includes EQ commodities), nuclear instrumentation, reactor protection, safeguard panels, and station grounding system. The mechanical systems (identified in Table 2.2-1 of the LRA), and thus their associated electrical component commodity groups, determined to be in scope include auxiliary feedwater and condensate, chemical and volume control, component cooling water, containment cooling, containment isolation, containment post-accident monitoring, containment spray, demineralized makeup water (Unit 2 only), diesel generators and support systems, emergency cooling canal, FP, fuel pool cooling, instrument air, ICW, main feedwater and steam generator blowdown, main steam, auxiliary steam, and turbine (includes main generator), miscellaneous bulk gas supply, primary makeup water, reactor coolant, safety injection, sampling, service water, turbine cooling water (Unit 1 only), ventilation, and waste management system.

2.5.1.2 Component-Level Scoping Results

2.5.1.2.1 Out-of-Scope Electrical, I&C, and Mechanical Components

The electrical/I&C component commodity groups associated with electrical, I&C, and mechanical systems (identified in Section 2.5.1 of the LRA) determined to be out of scope for license renewal include electrical buses, transmission conductors, and high-voltage insulators.

2.5.1.2.2 In-scope Electrical, I&C, and Mechanical Components

The electrical/I&C component commodity groups associated with electrical, I&C, and mechanical systems (identified in Table 2.5-1 of the LRA) determined to be in scope for license renewal include alarm units (including fire detectors), circuit breakers, fuses, signal conditioners, analyzers, generators, motors, solenoid operators, annunciators, communication equipment, solid-state devices, batteries, high-voltage surge arrestors, indicators, switches, isolators, light bulbs, cables/connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks), bus, electrical portions of electrical/I&C penetration assemblies, electric heaters, heat tracing, loop controllers, internal component assemblies for switchgears, load centers, motor control centers, and distribution panels, meters, power supplies, transformers, electrical/I&C and panel internal component assemblies, radiation monitors, recorders, regulators, chargers, converters, inverters, elements, resistance temperature detectors (RTDs), sensors, thermocouples, transducers, relays, and transmitters.

2.5.1.3 Component-Level Screening and Scoping Results

The component commodity groups of the systems found to be in scope identified as being subject to an AMP consist of cables and connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks) not included in the 10 CFR 50.49 Environmental Qualification Program.

2.5.2 Staff Evaluation

2.5.2.1 Scoping—10 CFR 54.4(a)

2.5.2.1.1 Offsite System

Section 2.5.1 of the LRA indicates that the generation and distribution system (which includes electrical bus, transmission conductor, and high-voltage insulator component commodity groups) does not meet any of the scoping criteria of 10 CFR 54.4(a). The staff disagreed with this conclusion. According to 10 CFR 54.4(a)(3), all systems, structures, and components relied on (in safety analyses or plant evaluations) to perform a function that demonstrates compliance with the NRC's regulations for station blackout (10 CFR 50.63) must be included within the scope of license renewal. Also, 10 CFR 50.63 requires that each light-water-cooled power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration. The establishment of this specified duration (or coping) can be based on plant evaluations that follow the guidance in NRC Regulatory Guide 1.155 and NUMARC 87-00. This guidance requires that the plant evaluation consider offsite system characteristics such as the expected frequency of loss of offsite power and the probable time needed to recover offsite power. Offsite systems (i.e., the generation and distribution system at St. Lucie) can be relied on in plant evaluations to perform a function that demonstrates compliance with the NRC regulations for station blackout (10 CFR 50.63). Thus, pursuant to 10 CFR 54.4(a)(3), offsite systems (the generation and distribution system) are required to be included within the scope of license renewal.

The staff pursued offsite system scoping generically and held several public meetings on the subject. From this generic pursuit, the staff by letter dated April 1, 2002, issued the following NRC staff position on the license renewal rule (10 CFR 54.4) as it relates to the station blackout rule (10 CFR 50.63).

<u>Staff Position</u>

Consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), the plant system portion of the offsite power system should be included within the scope of license renewal. The reasons for support of this position follow:

<u>Rationale</u>

The license renewal rule, 10 CFR 54.4(a)(3), requires that, "All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for.....station blackout (10 CFR 50.63)" be included within the scope of license renewal. The station blackout (SBO) rule, 10 CFR 50.63(a)(1), requires that each light-water-cooled nuclear power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration that is based upon factors that include: "(iii) The expected frequency of loss of offsite power; and (iv) The probable time needed to restore offsite power." The SBO rule in this regard is consistent with the staff findings identified in the statement of considerations and NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants." In particular, with regard to factor (iv), the staff found that offsite power is more likely to be restored (0.6 hours median time to restore) than the emergency diesel generators (8 hours median time to repair) in terminating an SBO event.

Station Blackout is the loss of offsite and onsite AC electric power to the essential and non-essential switchgear buses in a nuclear power plant. It does not include the loss of AC power fed from inverters powered by station batteries nor loss of AC power from an SBO defined alternate AC power source. The SBO rule was added to the regulations in 10 CFR Part 50 because, as operating experience accumulated, concern arose that the reliability of both the offsite and onsite AC power systems might be less than originally anticipated, even for designs that met the requirements of General Design Criteria 17 and 18. As a result, the SBO rule required that nuclear power plants have the capability to withstand and recover from the loss of offsite and onsite AC power of a specified duration (the coping duration).

Licensees' plant evaluations followed the guidance specified in NRC Regulatory Guide (RG) 1.155 and NUMARC 87-00 to determine their required plant-specific coping duration. The criteria specified in RG 1.155 to calculate a plant-specific coping duration were based upon the expected frequency of loss of offsite power and the probable time needed to restore offsite power, as well as the other two factors (onsite emergency AC power source redundancy and reliability) specified in 10 CFR 50.63(a)(1). In requiring that a plant's coping duration be based in part on the probable time needed to restore offsite power, 10 CFR 50.63(a)(1) is specifying that the offsite power system be an assumed method of recovering from an SBO. Disregarding the offsite power system as a means of recovering from an SBO would not meet the requirements of the rule and would result in a longer required coping duration.

The use of the offsite power system within 10 CFR 50.63(a)(1) as a means of recovering from an SBO should not be construed to be the only acceptable means of recovering from an SBO. A licensee could for example recover offsite power or emergency (onsite) power. It is not possible to determine prior to an actual SBO event which source of power can be returned first. As a result, 10 CFR 50.63(c)(1)(ii) and its associated guidance in RG 1.155, Sections 1.3 and 2, require procedures to recover from an SBO that include restoration of offsite and onsite power.

Based on the above, both the offsite and onsite power systems are relied upon to meet the requirements of the SBO rule. Elements of both offsite and onsite power are necessary to determine the required coping duration under 10 CFR 50.63(a)(1), and the procedures required by 10 CFR 50.63(c)(1)(ii) must address both offsite power and onsite power restoration. It follows, therefore, that both systems are used to demonstrate compliance with the SBO rule and must be included within the scope of license renewal consistent with the requirements of 10 CFR 54.4(a)(3). License renewal applicants are presently including the onsite power system within the scope of license renewal on the basis of the requirements under 10 CFR 54.4(a)(1) (safety-related systems). They are also including equipment that is relied upon to cope with an SBO (e.g., alternate AC power sources) on the basis of the requirements under 10 CFR 54.4(a)(3). Only the addition of the offsite power system is therefore necessary to complete the required scope of the electrical power systems under license renewal.

The offsite power systems of U.S. nuclear power plants consist of a transmission system (grid) component that provides a source of power and a plant system component that connects that power source to a plant's onsite electrical distribution system which powers safety equipment. The staff has historically relied upon the well-distributed, redundant, and interconnected nature of the grid to provide the necessary level of reliability to support nuclear power plant operations. For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive SCs that are part of this circuit path are subject to an AMR will assure that the bases underlying the SBO requirements are maintained over the period of the extended license. This is consistent with the Commission's expectations in including the SBO regulated event under 10 CFR 54.4(a)(3) of the license renewal rule.

By NRC letter dated July 1, 2002, the staff requested the applicant to (a) describe (consistent with the above defined staff position) the process used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3) and (b) provide a list of those additional component commodity groups identified to be within scope as a result of this evaluation. By letter dated September 26, 2002, the applicant identified the electrical component commodity groups included in the scope of license renewal as meeting the scoping criteria of 10 CFR 54.4(a)(3) for restoration of offsite power. They include circuit breakers and switches to connect the startup transformer circuits to the grid, batteries and DC controls associated with the startup transformer circuit breakers; startup transformers; non safety-related 4.16 kV switchgear; DC control and power (lead sheath) cables; all aluminum alloy conductor (Type AAAC) transmission conductors between the startup transformers and circuit breakers; high-voltage insulators associated with the transmission conductors; switchyard bus and connections between the startup transformers and circuit breakers; and nonsegregated-phase bus between the startup transformers and the non-safety-related 4.16 kV switchgear.

2.5.2.1.2 Fuse Holders

Following discussion with the NRC during the public meetings on September 4 and 5, 2002, the applicant was requested to address the NRCs May 16, 2002, letter entitled, "Proposed Staff Guidance on the Identification and Treatment of Electrical Fuse Holders for License Renewal." The applicant, by letter dated October 3, 2002, in response to RAI 2.5-1, indicated that it agrees with the NRC position that fuse holders are within the scope of license renewal.

2.5.2.2 Passive Screening—10 CFR 54.21(a)(1)(i)

From the electrical/I&C component commodity groups identified in Table 2.5-1 of the LRA, cables and connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks) and electrical/I&C penetration assemblies (electrical portions) were determined to meet the screening criterion of 10 CFR 54.21(a)(1)(i). In addition, by letter dated October 3, 2002, in response to RAI 2.5-1, the applicant indicated that fuse holders/blocks are classified as a specialized type of terminal block because of the similarity in design and construction and that fuse holders within the scope of license renewal that are not included as a piece part of a larger active commodity group, such as switchgear, were determined to meet the passive screening criterion of 10 CFR 54.21(a)(1)(i).

In addition, the passive electrical/I&C component commodity groups identified in Section 2.5.1 of the LRA initially determined to be out of scope for license renewal based on plant-level scoping results include electrical buses, transmission conductors, and high-voltage insulators. Subsequently, these commodity groups (based on the applicant's September 26, 2002, response to the staff's SBO position, described above) were identified to be within the scope of license renewal and were also identified to meet the passive screening criterion of 10 CFR 54.21(a)(1)(i).

Passive component commodity groups (for which aging degradation is not readily monitored) are those that perform an intended function without moving parts or without a change in configuration or properties. As examples of passive component commodity groups, 10 CFR 54.21(a)(1)(i) conveys that electrical component commodity groups meeting this passive definition include, but are not limited to, electrical penetrations, cables, and connections, and exclude, but are not limited to, motors, diesel generators, pressure transmitters, pressure indicators, water-level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies.

The staff reviewed the component commodity groups identified above to verify that the applicant did not omit any passive component commodity groups and that they meet the above defined passive screening criteria and/or examples conveyed by 10 CFR 54.21(a)(1)(i). The staff concluded that the above identified component commodity groups are consistent with the examples of passive component commodity groups conveyed by 10 CFR 54.21(a)(1)(i) and are therefore considered acceptable. In addition, these component commodity groups were found to be the same as the passive determinations described in NEI 95-10 (Revision 3), Appendix B, for component commodity groups in the electrical category. The staff has reviewed these NEI determinations and concluded (1) that each component commodity group identified performs its intended function without moving parts or without a change in configuration or properties and its aging degradation is not readily monitored and (2) that these component commodity groups acceptably identify passive component commodity groups pursuant to 10 CFR 54.21(a)(1)(i). Therefore, the staff agrees that the above identified subgroup of electrical/I&C component commodity groups within the scope of license renewal represents the passive electrical/I&C component commodity groups that would be required to be included in an AMR if they also meet long-lived screening criteria.

2.5.2.3 Long-Lived Screening—10 CFR 54.21(a)(1)(ii)

From the subgroup electrical/I&C component commodity groups identified to be within scope and to be passive, the applicant eliminated component commodity groups that are required to meet 10 CFR 50.49. Thus, the component commodity groups identified as meeting the long-lived screening criterion of 10 CFR 54.21(a)(1)(ii) and subject to an AMR include cables and connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks) not included in the St. Lucie 10 CFR 50.49 EQ Program.

In addition, by letter dated October 3, 2002, in response to RAI 2.5-1, the applicant indicated that fuse holders/blocks are classified as a specialized type of terminal block that likewise meet the long-lived screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

In addition, in Section 2.5.1 of the LRA, several passive electrical/I&C commodity groups were initially determined to be out of scope for license renewal based on plant-level scoping results. These include electrical buses, transmission conductors, and high-voltage insulators. Subsequently, these component commodity groups (based on the applicant's September 26, 2002, response to the staff's SBO position, described above) were identified to be within the scope of license renewal, were identified to meet passive screening criterion

10 CFR 54.21(a)(1)(i), and were also identified to meet the long-lived screening criterion of 10 CFR 54.21(a)(1)(ii). Thus, they are subject to an AMR.

A component that is not replaced either (1) on a specified interval based upon the qualified life of the component or (2) periodically in accordance with a specified time period is deemed to be "long-lived," and therefore subject to an AMR. Components subject to EQ aging requirements pursuant to 10 CFR 50.49(e)(5) are required to be replaced or refurbished at the end of their designated life. These components, pursuant to 10 CFR 50.49(e)(5), are subject to replacement based on a qualified life or on a specified time period. The applicant conveyed in the LRA that the above identified component commodity groups are not included in their 10 CFR 50.49 EQ Program and are not subject to aging requirements of 10 CFR 50.49(e)(5). The staff, therefore, agrees that the above identified component commodity groups meet long-lived screening criteria and are thus subject to an AMR.

Based on the preceding review, the staff did not find any omissions.

2.5.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the electrical and I&C system components subject to the AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

3. AGING MANAGEMENT REVIEW RESULTS

3.0 Aging Management Programs

3.0.1 Introduction

This section of the safety evaluation report (SER) contains the staff's evaluation of the aging management programs (AMPs) that are referenced in the aging management review (AMR) for two or more systems and/or structures and are therefore considered common AMPs. The remaining programs are system-specific and will be evaluated at the beginning of subsequent sections of this SER. It should be noted that the staff's conclusions on the evaluations of these system-specific AMPs may be predicated on the assumption that the AMPs are implemented in conjunction with other AMPs (if more than one AMP is credited by the applicant) as discussed in subsequent sections of this SER.

The applicant claimed that 11 of the AMPs are consistent with the programs described in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." The description of the staff's review of these AMPs, which are consistent with the GALL Report, is contained in Section 3.0.2 of this SER. The description of the staff's review of the AMPs that are not consistent with the GALL Report is contained in Section 3.0.3 of this SER. The description of the staff's review of Florida Power and Light Company's (FPL's) Quality Assurance Program is contained in Section 3.0.4 of this SER. The common AMPs are evaluated in Section 3.0.5 of this SER.

Table 3.0.1-1 of this SER presents the common AMPs, the associated GALL Report program if applicable, the system groups that credit the program for management of component aging, and the SER section that contains the staff's review of the program.

Table 3.0.1-1 Common Aging Management Programs

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Galvanic Corrosion Susceptibility Inspection Program (B.3.1.2)	None	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.5.1
Pipe Wall Thinning Inspection Program (B.3.1.3)	None	3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.5.2
ASME Section XI, Subsections IWB, IWC, and IWD (Inservice Inspection Program (B.3.2.2.1)	XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD"	3.1—RCS 3.2—ESF	3.0.5.3

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Boric Acid Wastage Surveillance Program (B.3.2.4)	XI.M10, "Boric Acid Corrosion"	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 35—Structures	3.0.5.4
Chemistry Control Program— Water Chemistry Control Subprogram (B.3.2.5.1)	XI.M2, "Water Chemistry"	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.5.5
Chemistry Control Program— Closed-Cycle Cooling Water System Chemistry Subprogram (B.3.2.5.2)	XI.M21, "Closed-Cycle Cooling Water System"	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.5.6
Fire Protection Program (B.3.2.8)	None	3.3—Auxiliary 3.5—Structures	3.0.5.7
Flow-Accelerated Corrosion Program (B.3.2.9)	XI.M17, "Flow-Accelerated Corrosion"	3.1—RCS 3.4—Steam and Power Conversion	3.0.5.8
Periodic Surveillance and Preventive Maintenance Programs (B.3.2.11)	None	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.5.9
Systems and Structures Monitoring Program (B.3.2.14)	None	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.5.10

Table 3.0.1-2 of this SER presents the system-specific AMPs, the associated GALL Report program if applicable, the system group that credits the program for management of component aging, and the SER section that contains the staff's review of the program.

Table 3.0.1-2 System-Specific Aging Management Programs

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Condensate Storage Tank Cross-Connect Buried Piping Inspection (Unit 1 only) (B.3.1.1)	None	3.4—Steam and Power Conversion	3.4.0.1
Reactor Vessel Internals Inspection Program (B.3.1.4)	None	3.1—RCS	3.1.0.7
Small Bore Class 1 Piping Inspection (B.3.1.5)	None	3.1—RCS	3.1.0.3
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.3.1.6)	XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	3.1—RCS	3.1.0.2
Alloy 600 Inspection Program (B.3.2.1)	None	3.1—RCS	3.1.0.1
ASME Section XI, Subsection IWE Inservice Inspection Program (B.3.2.2.2)	XI.S1, "ASME Section XI, Subsection IWE" XI.S4, "10 CFR 50, Appendix J"	3.5—Structures	3.5.0.1
ASME Section XI, Subsection IWF Inservice Inspection Program (B.3.2.2.3)	XI.S3, "ASME Section XI, Subsection IWF"	3.5—Structures	3.5.0.2
Boraflex Surveillance Program (Unit 1 only) (B.3.2.3)	XI.M22, "Boraflex Monitoring"	3.5—Structures	3.5.0.3
Chemistry Control Program—Fuel Oil Chemistry Subprogram (B.3.2.5.3)	None	3.3—Auxiliary	3.3.0.1
Environmental Qualification Program (B.3.2.6)	None	3.6—Electrical	TLAA 4.4
Fatigue Monitoring Program (B.3.2.7)	None	3.1—RCS	3.1.0.6

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Intake Cooling Water System Inspection Program (B.3.2.10)	None	3.3—Auxiliary	3.3.0.2
Reactor Vessel Integrity Program (B.3.2.12)	None	3.1—RCS	3.1.0.5
Steam Generator Integrity Program (B.3.2.13)	XI.M19, "Steam Generator Tube Integrity"	3.1—RCS	3.1.0.4
Non-EQ Cable and Connection Aging Management Program (Response to RAI 3.6-1; letter dated 11/27/02)	None	3.6—Electrical	3.6.0.1

3.0.2 Aging Management Programs Consistent with GALL

3.0.2.1 The GALL Evaluation Process

Following the general format of NUREG-1800, "Standard Review Plan for Review of the License Renewal Applications for Nuclear Power Plants," the staff reviewed the aging effects on structures and components (SCs), identified the relevant existing programs, and evaluated program elements to manage aging effects for license renewal. The staff's evaluation of the adequacy of each generic AMP in managing certain aging effects for particular SCs is based on the review of the following 10 program elements.

(1) program scope
(2) preventive actions
(3) parameters monitored or inspected
(4) detection of aging effects
(5) monitoring and trending
(6) acceptance criteria
(7) corrective actions
(8) confirmation process
(9) administrative controls
(10) operating experience

These elements are described in Appendix A of NUREG-1800 and in the GALL Reports.

The staff documented acceptable generic AMPs, such as the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Water Chemistry, and Structures Monitoring Programs, in Chapter XI of the GALL Report. If the material presented in the GALL Report is applicable to the applicant's facility, the staff will find the applicant's response acceptable. In making this determination, the staff will consider whether the applicant has identified specific programs described and evaluated in the GALL Report. The staff, however, will not conduct a re-review of the substance of the matters described in the GALL Report. Rather, the staff will ensure the applicant verifies that the approvals set forth in the GALL Report for generic programs apply to the applicant's programs.

The focus of the staff's review is on augmented programs for license renewal. For the AMPs that are not consistent with the GALL Report, the reviewer will evaluate the 10 elements described in Appendix A of NUREG-1800 and the GALL report as outlined above. The staff's review of these AMPs is described in Section 3.0.3 of this SER.

If an applicant takes credit for an AMP being consistent with the GALL Report, the applicant must ensure that the plant program contains all the elements of the referenced GALL program. In addition, the conditions at the plant must be bounded by the conditions for which the GALL program was evaluated. The above verifications must be documented on site in an auditable form. The applicant must include a certification in the renewal application that the verifications have been completed and are documented on site in an auditable form. The staff will confirm that these AMPs are consistent with the GALL Report during onsite inspections and will document its findings in an inspection report.

In order to determine if evaluating AMRs and AMPs for consistency with the GALL Report would improve the efficiency of the license renewal review, the staff and industry conducted a demonstration project to exercise the GALL process and to determine the format and content of a safety evaluation based on the GALL review process. NUREG-1800 was prepared based on both the GALL model and the lessons learned from the demonstration project. On the basis of these lessons learned from the demonstration project, the staff determined that if an applicant commits to implementing the staff-approved AMPs identified in the GALL Report, the time, effort, and resources used to review an applicant's License Renewal Application (LRA) will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process.

3.0.2.2 The Staff's Review Process for Programs Consistent with the GALL Report

FPL is the first license renewal applicant to utilize the GALL Report for evaluating its AMPs. The staff's review of the St. Lucie Units 1 and 2 AMPs was performed in three phases. In Phase 1, the staff reviewed the AMPs that the applicant claimed were consistent with the GALL Report. The staff compared these AMPs to the associated AMPs described in Section XI of the GALL Report. The AMPs will be discussed further in the sections of this SER identified in Table 3.0.1. For the AMPs for which the GALL Report recommended further evaluation, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report.

For those AMPs that are not consistent with the GALL Report, the staff evaluated the AMPs against the 10 program elements described in the Appendix A of the SRP-LR. The staff's review of these AMPs is described in Section 3.0.3 of this SER. The staff also reviewed the final safety analysis report (FSAR) supplements in Appendix A of the LRA for each AMP to determine whether they provided an adequate description of the program or activity, as required by Section 54.21(d) of Title 10 of the U.S. *Code of Federal Regulations* (CFR).

In Phase 2, the staff determined whether the applicant's AMRs and associated AMPs were adequate to manage the aging effects for which they were credited. In Phase 3, the staff reviewed plant-specific SCs to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite inspection to confirm the applicant's claim that specific AMPs were consistent with the AMPs in the GALL Report. The staff generated Open Item 3.0.2.2-1 to track this verification. The AMR inspection was completed on January 31, 2003, and documented in NRC Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The inspection findings verified the applicant's claim that specific AMPs were consistent with the GALL Report. Therefore, the staff considers Open Item 3.0.2.2-1 to be closed.

3.0.3 Aging Management Programs Not Consistent with the GALL Report

The staff's evaluation of the applicant's AMPs that are not consistent with the GALL Report focuses on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff used 10 elements to evaluate each program and activity. The 10 elements of an effective AMP were developed as part of NUREG-1800, "Standard Review Plan for License Renewal," which was issued in July 2001. This SER describes the extent to which the 10 elements, as described in Appendix A of NUREG-1800 (Branch Technical Position, A.1 Aging Management Review Generic), are applicable to a particular program or activity, and evaluates each program and activity against those elements. On the basis of NRC experience with maintenance programs and activities, the staff concluded that conformance with the 10 elements of an AMP, or a combination of AMPs, provides reasonable assurance that an AMP (or combination of programs and activities) is effective at managing an applicable aging effect. The 10 elements of an effective AMP will be considered in evaluating each AMP used by the applicant to manage the applicable aging effects identified within this SER.

In the LRA, Appendix B, Section 2.0, "Attribute Definitions," the applicant described the elements involving corrective actions and confirmation processes for license renewal. The staff's evaluation of the applicant's quality assurance attributes associated with the AMPs credited for license renewal is discussed below.

3.0.4 Florida Power and Light Quality Assurance Program Attributes Integral to Aging Management Programs

The NRC staff has reviewed LRA Appendix B, Section 2.0, "Aging Management Program Attributes," in accordance with the requirements of 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes, namely corrective actions, confirmation process, and administrative controls. These three attributes of the Quality Assurance Program are addressed for all of the applicant's AMPs.

The license renewal applicant is required to demonstrate that the effects of aging on SCs that are subject to an AMR will be adequately managed to ensure that their intended function(s) will be maintained in a manner that is consistent with the CLB of the facility throughout the period of extended operation as required by 10 CFR 54.21(a)(3). To manage these effects, applicants have developed new or revised existing AMPs and applied those programs to the Structures, Systems, and Components (SSCs) of interest. For each of these AMPs, the existing 10 CFR Part 50, Appendix B, Quality Assurance Program may be used to address the attributes of corrective actions, confirmation process, and administrative controls.

3.0.4.1 Summary of Technical Information in Application

Chapter 3.0, "Aging Management Review Results," of the LRA provides an AMR summary for each unique structure, component, or commodity group at St. Lucie determined to require aging management during the period of extended operation as required by 10 CFR 54.21(a)(3). This summary includes identification of aging effects requiring management and AMPs utilized to manage these aging effects. Appendix B to the LRA demonstrates how the identified programs manage aging effects using attributes consistent with the industry and NRC guidance. Specifically, the applicant used the following specific attributes to describe these programs and activities.

1. Corrective Actions — This attribute is a description of the action taken when the established acceptance criterion or standard is not met. This includes timely root-cause determination and prevention of recurrence, as appropriate.

2. Administrative Controls — This attribute is an identification of the plant administrative structure under which the programs are executed.

3. Scope — This attribute is a clear statement of the reason why the program exists for license renewal.

4. Preventive Actions — This attribute is a description of preventive actions taken to mitigate the effects of the susceptible aging mechanisms and of the basis for the effectiveness of these actions.

5. Parameters Monitored or Inspected — This attribute is a description of parameters monitored or inspected, and how they relate to the degradation of the particular component or structure, and its intended function.

6. Detection of Aging Effects —This attribute is a description of the type of action or technique used to identify or manage the aging effects or relevant conditions.

7. Monitoring and Trending — This attribute is a description of the monitoring, inspection, or testing frequency, and sample size (if applicable).

8. Acceptance Criteria — This attribute is an identification of the acceptance criteria or standards for the relevant conditions to be monitored or the chosen examination methods.

9. Confirmation Process — This attribute is a description of the process to ensure that adequate corrective actions have been completed and are effective.

10. Operating Experience and Demonstration — This attribute is a summary of the operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs.

In Section 2.0 of Appendix B to the LRA, the applicant provides a generic description of the corrective actions and administrative controls common to all AMPs credited for license renewal. In this section, the applicant states that the corrective actions and administrative controls apply to all AMPs that are credited for license renewal. The confirmation process description for each AMP is incorporated directly into the AMP. Those descriptions contain a statement about the confirming processes for each AMP which include followup inspections, tests, or examinations, if required, based upon actual programmatic criteria, such as corrosion rates, material conditions, or prior inspection or examination findings. Those confirming processes are documented in accordance with the Corrective Action Program. The corrective actions and administrative controls are described as part of the applicant's Quality Assurance Program required by 10 CFR Part 50, Appendix B. For each AMP listed in Section 3.0, "Aging Management Programs," of Appendix B to the LRA, the confirmation process is described as establishing followup examination or inspection requirements based on the evaluation of the inspection results. Also, the applicant states that it will specify unacceptable evaluation results in its Corrective Action Program.

Additionally, the applicant noted that the FPL Corrective Action Program is an existing and effective program for identifying, evaluating, and correcting deficiencies, and is implemented in accordance with the Quality Assurance Program. Under the guidance of the FPL Quality Assurance Program, quality instructions and administrative procedures for corrective actions require that any deficiency documented by an individual be evaluated, dispositioned, and either corrected or declared acceptable in accordance with the deficiency disposition. These procedures and instructions provide guidance on documentation, evaluation, completion, and confirmation actions, including follow up of corrective actions.

3.0.4.2 Staff Evaluation

The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes, namely corrective actions, confirmation process, and administrative controls. These three attributes of the quality Assurance Program are used by all of the applicant's AMPs.

During the audit of the St. Lucie scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated UFSAR Supplement," and Appendix B, "Aging Management Programs," to assure that the aging management activities were consistent with the staff's guidance described in Section A.2, "Quality Assurance for Aging Management Programs," and Branch Technical Position IQMB-1, regarding quality assurance of the Standard Review Plant for License Renewal (SRP-LR). During the review, the applicant stated that the attributes of corrective action, confirmation process, and administrative control were developed and are integral to the site Quality Assurance Programs. The audit team confirmed that the applicant credited this process for both the safety-related and non-safety-related SSCs within the scope of license renewal. In addition, the staff verified that the definitions for each of the attributes of the AMPs were consistent with those definitions in Section A.2 of NUREG-1800.

Based on the staff's evaluation, the description and applicability of the AMPs, and their associated attributes to all safety-related and non-safety-related SCs provided in Appendix B to the LRA, are consistent with the staff's position regarding quality assurance for aging management. However, the staff noted that the applicant had not sufficiently described the use of the Quality Assurance Program and its associated attributes in the UFSAR supplements discussion provided in Appendix A to the LRA. In a letter dated July 1, 2002, the staff requested that the applicant revise its description in Appendix A, "Updated UFSAR Supplement," of the LRA to include aspects of the Quality Assurance Program consistent with the description provided in Appendix B of the LRA (Request for Additional Information [RAI] 2.1-3).

In a letter dated September 26, 2002, (FPL Letter No. L-2002-139), the applicant provided a response to the staff's RAI. In that response, the applicant further described the Quality Assurance Program and provided a revised introductory description for the UFSAR supplements. Specifically, the applicant stated that the FPL Corrective Action Program is an existing and effective program for identifying, evaluating, and correcting deficiencies and is implemented in accordance with FPL's 10 CFR 50 Appendix B Quality Assurance Program. Under the guidance of the FPL Quality Assurance Program, quality instructions and administrative procedures for corrective actions require that any deficiency documented by an individual be evaluated, dispositioned, and either corrected or declared acceptable in accordance with the deficiency disposition. These procedures and instructions provide guidance on documentation, evaluation, completion, and confirmation actions, including followup of corrective actions. Accordingly, the confirmation process is part of the Corrective Action Program and the FPL Quality Assurance Program. Additionally, deficiencies identified during the performance of inspections or activities associated with any AMP or time-limited aging analyses (TLAAs) will be entered into the appropriate Corrective Action Program and actions, including confirmation activities, will be performed accordingly.

In its response to the staff's RAI, the applicant has committed to revise the St. Lucie Unit 1 and 2 UFSAR supplements (LRA Appendices A1 and A2) to state the following.

> FPL has established and implemented a Quality Assurance Program to provide assurance that the design, procurement, modification and operation of nuclear power plants conform to applicable regulatory requirements. The FPL Quality Assurance Program, described in the FPL Topical Quality Assurance Report, is in compliance with the requirements of 10 CFR 50, Appendix B. For all aging management programs credited for license renewal, the program attributes of Corrective Actions, Confirmation, and Administrative Controls are performed or, in the case of new programs will be performed, in accordance with the FPL Quality Assurance Program, and will apply to all components and structural components within the scope of the programs, including non safety-related components and structural components.

On the basis of the information provided in the LRA, as supplemented by the applicant's response to the staff's RAI dated July 1, 2002, the NRC staff has determined that for all AMPs credited for license renewal, the corrective actions, confirmation process, and administrative controls are addressed in the applicant's approved Quality Assurance Program. The staff finds that the FPL Topical Quality Assurance Report contains the applicant's commitments for managerial and administrative controls, including a discussion of how the applicable requirements of Appendix B to 10 CFR Part 50 will be satisfied. Therefore, RAI 2.1-3 is considered resolved.

3.0.4.3 Conclusion

The staff finds that the quality assurance attributes are consistent with 10 CFR 54.21(a)(3). The staff finds that the applicant's descriptions in Chapter 18 of the UFSAR supplements, as revised in its response dated September 26, 2002, to the staff's RAI 2.1-3, provide a sufficient description of the quality assurance attributes and activities for managing the effects of aging. Therefore, the applicant's quality assurance attributes within the AMPs credited for license renewal are acceptable.

3.0.5 Common Aging Management Programs

3.0.5.1 Galvanic Corrosion Susceptibility Inspection Program

The Galvanic Corrosion Susceptibility Inspection Program is described in Section 3.1.2 of Appendix B to the LRA. This program provides aging management of component/commodity groups of several systems (listed in Section 3.0.5.1.1 of this SER) for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Galvanic Corrosion Susceptibility Inspection Program will adequately manage the aging effects for components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.1.1 Summary of Technical Information in the Application

In Section 3.1.2 of Appendix B to the LRA, the applicant describes a new program that characterizes loss of material due to galvanic corrosion caused by exposure to air/gas (wetted due to condensation), treated water, and raw water (including city water) environments. The applicant's Galvanic Corrosion Susceptibility Inspection Program is credited with the aging management of specific component/commodity groups in the following systems.

- auxiliary Feedwater and condensate
- component cooling water
- containment cooling
- containment spray
- diesel generator and support systems
- fire protection
- fuel pool cooling
- instrument air
- main Feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine
- primary makeup water
- safety injection
- turbine cooling water (Unit 1 only)
- ventilation

The applicant's program is credited for managing the potential loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. Loss of material is expected mainly in carbon steel components directly coupled to stainless steel components in raw water systems; however, the applicant stated that baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The program involves one-time inspections, the results of which will be utilized to determine the need for additional programs and will be implemented prior to the end of the initial operating license term for St. Lucie.

The applicant's Galvanic Corrosion Susceptibility Inspection Program is a new program that will use techniques with demonstrated capability and a proven industry record to monitor material loss due to galvanic corrosion. The applicant's examinations will be performed utilizing approved plant procedures and qualified personnel. The inspection techniques that will be used in this program have been used previously to monitor material condition for plant systems. This program will quantify the significance of this potential aging effect. This is a one-time inspection, and the locations selected for inspection will represent those with the greatest susceptibility to galvanic corrosion. Initial inspection results will be used to assess the need for expanded sample locations. The applicant provided additional information about this program in its letter dated September 26, 2002, in response to RAI B.3.1.2-1.

3.0.5.1.2 Staff Evaluation

The staff reviewed the information in Section 3.1.2 of Appendix B to the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions in the UFSAR supplements of the Galvanic Corrosion Susceptibility Inspection Program in Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 to the LRA. The staff's evaluation of the applicant's Galvanic Corrosion Susceptibility Inspection Program focused on how the program manages aging effects through the effective incorporation of 10 elements—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of the Quality Assurance Program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: This program is credited for managing the potential loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The applicant expects loss of material mainly in carbon steel components directly coupled to stainless steel components in raw water systems. Baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The applicant noted that this program involves one-time inspections, the results of which will be utilized to determine the need for additional programmatic actions.

The applicant further stated that since the inspection of all locations with the potential for galvanic corrosion is not practical, an engineering specification will be developed to provide the methodology for identifying those galvanic couples where corrosion is most likely to occur and where inspection results can be used to bound less susceptible locations. Selection of locations with greatest susceptibility to galvanic corrosion will be based on (1) how far apart the two dissimilar metals are on the galvanic series chart, (2) the conductivity of the electrolyte, and (3) the relative size of the anode and cathode.

The overall susceptibility of each galvanic couple in each system is assessed and ranked based upon consideration of the above factors. Those with greatest susceptibility are then recommended for inspection. Those that are not selected for inspection are verified to be bounded based upon electrical potential of dissimilar materials, purity of water (i.e., conductivity), and relative size of anode and cathode. For those cases in which the combination of two influencing factors do not provide a conclusive ranking, the particular galvanic cell is selected for inspection. The selection process will ensure that a variety of environments are addressed by inspection including treated water—other, borated water, raw water—city water (fire protection), and air/gas—wetted air (condensation). The staff finds the scope of this program to be acceptable because the applicant will be examining those components most likely to experience galvanic corrosion and will apply the results of these examinations to other systems and components.

Preventive Actions: The applicant noted that some components and systems utilize insulating flanges or cathodic protection as preventive measures to minimize galvanic interaction. Furthermore, the applicant noted that the use of insulating flanges and cathodic protection performs a preventive function, but is not credited for elimination of galvanic corrosion. The staff determined that the purpose of the program is to visually examine those areas within the scope of the program and take corrective action where required. Therefore, preventive or mitigative actions are not required.

Parameters Monitored or Inspected: Techniques such as ultrasonic examinations to measure the thickness of the components for material loss and visual examinations to examine the condition of the component for discoloration, overall condition, and other signs of corrosion will be performed on the susceptible components. These examination methods are consistent with current industry practice and are capable of identifying thinning of the selected components and thus are acceptable. Therefore, the staff finds the applicant's parameters monitored and inspection methods acceptable.

Monitoring and Trending: Since this is a one-time inspection, there are no monitoring and trending aspects to this program. The staff finds this acceptable.

Detection of Aging Effects: As discussed above, the staff finds the inspection program scope and technique to be applied to be acceptable. With respect to inspection timing, the applicant did not provide the staff with a schedule other than to state that the Galvanic Corrosion Susceptibility Inspection Program will be implemented prior to the expiration of the initial operating license term for St. Lucie (i.e., is the 40^{th} year of operation). The staff did not identify the need for a specific commitment from the applicant to perform a galvanic susceptibility inspection at a particular time. Thus, recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the LRA, the staff accepts the applicant's general commitment to complete the Galvanic Corrosion Susceptibility Inspection Program before the end of the 40^{th} year of operation because the staff expects minimal progression for aging effects due to the robust design and relatively benign operating conditions. In conclusion, the staff finds that the inspection scope, technique, and schedule support the applicant's intention of confirming that this corrosion mechanism need not be managed for the period of extended operation.

Acceptance Criteria: The applicant's program consists of a confirmatory, one-time inspection of piping to verify that loss of material due to galvanic corrosion is not occurring. Furthermore, the applicant noted that in the event that significant loss of material is detected during the inspection, appropriate corrective actions will be taken in accordance with the Corrective Action Program. The applicant indicated that evaluation of the inspection results will consider the measured wall thickness, calculated corrosion rate, and projected wall thickness, and will ensure that the minimum required wall thickness is maintained pursuant to the applicable code requirements. The staff finds the applicant's acceptance criteria reasonable and therefore acceptable.

Operating Experience: The Galvanic Corrosion Susceptibility Inspection Program was developed to quantify the significance of loss of material due to this corrosion mechanism and provide for managing the effects of aging, if required. This program constitutes a one-time inspection of selected locations in treated water and other systems which have been identified as potentially susceptible to galvanic corrosion. The other systems have internal environments of condensed atmosphere in portions of the instrument air and ventilation systems and raw water—city water in the fire protection systems. The applicant further stated that a review of the plant-specific operating experience for these other systems (i.e., the instrument air, ventilation, and fire protection systems) also did not identify significant galvanic corrosion. Therefore, they are included in the program for one-time inspection.

Although the applicant stated that significant galvanic corrosion has not been experienced and is not anticipated in treated water systems due to the high purity of the water and its low conductivity, the applicant had instances of galvanic corrosion at St. Lucie, primarily in the intake cooling water system. Galvanic corrosion for the intake cooling water (ICW) system is managed using the Intake Cooling Water System Inspection Program and the Systems and Structures Monitoring Program. The bottom of the Unit 1 refueling water tank, which is aluminum, developed a through-wall leak that was attributed to galvanic corrosion. Additionally, nozzles associated with the tank have experienced external galvanic corrosion at the flanges to the stainless steel piping due to water accumulation. Corrective actions for the tank included sealing the external tank bottom and lining the internal tank bottom with fiberglass-reinforced vinyl ester. Corrective actions for the nozzles included removing the insulation or changing the insulation to sealed rubber. Since these modifications, no further instances of galvanic corrosion have occurred at these locations. The staff concludes that the applicant's operating experience supports its proposed one-time Galvanic Corrosion Susceptibility Inspection Program.

3.0.5.1.3 UFSAR Supplement

Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 to the LRA provide the applicant's UFSAR supplements for the Galvanic Corrosion Susceptibility Inspection Program. The program descriptions are consistent with the material contained in Section 3.1.2 of Appendix B to the LRA, except Acceptance Criteria and parameters monitored or inspected. The staff generated Confirmatory Item 3.0.5.1-1 to track that the applicant will revise the UFSAR supplements to describe these two attributes consistent with the SER prior to issuance of the new licenses.

In its March 28, 2003, response to Confirmatory Item 3.0.5.1-1, the applicant provided revisions to Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 to the LRA for the Galvanic Corrosion Susceptibility Inspection Program. The staff verified that the UFSAR supplements identified that baseline examinations would be usual inspections or volumetric determinations, and that the inspection results would consider the minimum required wall thickness consistent with the applicable code. Therefore, the staff considers Confirmatory Item 3.0.5.1-1 closed.

3.0.5.1.4 Conclusions

The staff finds that the applicant has demonstrated that the effects of aging associated with the SCs of the Galvanic Corrosion Susceptibility Inspection Program will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.2 Pipe Wall Thinning Inspection Program

The applicant described its Pipe Wall Thinning Inspection Program in Section 3.1.3 of Appendix B to the LRA. The applicant credits this program with managing the aging of specific components in the Units 1 and 2 auxiliary Feedwater and condensate system and in the Unit 2 component cooling water system. The staff reviewed Section 3.1.3 of Appendix B to the LRA to determine whether the applicant has demonstrated that the Pipe Wall Thinning Inspection Program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.2.1 Summary of Technical Information in the Application

The Pipe Wall Thinning Inspection Program is a new program credited for aging management of specific component/commodity groups in the auxiliary Feedwater and condensate system in Units 1 and 2 and the component cooling water system in Unit 2. The program is plant-specific. There is no comparable AMP in the GALL Report.

The program provides for volumetric examination methods to detect loss of material by measuring wall thickness resulting from pipe wall erosion. It involves periodic inservice volumetric inspections and specifies minimum wall thickness acceptance criteria based on American National Standards Institute (ANSI) B31.7 and ASME Section III.

3.0.5.2.2 Staff Evaluation

The staff has reviewed the information provided in Section 3.1.3 of Appendix B to the LRA, the summary description of the Pipe Wall Thinning Inspection Program in Appendix A to the LRA, and the applicant's September 26, 2002, response to the staff's RAIs. The staff's evaluation of the Pipe Wall Thinning Inspection Program focused on how the applicant demonstrated that the applicable aging effects of the SCs that credit this program will be managed during the period of extended operation. The staff evaluated the program against the 10 elements that are described in Appendix A to NUREG-1800: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the inspections involves examination of auxiliary feedwater and condensate system stainless steel piping components downstream of the auxiliary feedwater recirculation orifices and carbon steel components in the Unit 2 component cooling water return piping. The staff considers the scope of this program acceptable because it covers the components that are susceptible to wall thinning.

Preventive Actions: The applicant stated that no preventive actions are applicable to this inspection, and the staff did not identify a need for any preventive or mitigating actions.

Parameters Monitored or Inspected: The program will assess the extent of localized wall thinning due to erosion of the internal surfaces of the monitored piping by the periodic measurement of the wall thickness at selected locations of the affected piping systems. The staff finds that measuring the wall thickness provides an acceptable method to assess the extent of the wall thinning.

Detection of Aging Effects: The applicant stated that the detection of loss of material will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing (UT) or radiography. The staff finds that these techniques effectively measure wall thickness and are acceptable.

Monitoring and Trending: The applicant stated that the frequency of inspections will be established based on the initial inspection results, considering the measured wall thickness, corrosion rates, and minimum required wall thickness. The need for any replacements or change in inspection frequency will be determined based on the results of each inspection.

In RAI B.3.1.3-3, the staff requested that the applicant provide an explanation of the apparent inconsistency between the terms "erosion rates" and "corrosion rates." In addition, the staff requested an explanation of how those rates are determined. By letter dated September 26, 2002, the applicant responded that the apparent inconsistency between the terms "erosion rates" and "corrosion rates" was the result of a typographical error. The text in the Monitoring and Trending portion should therefore read, "The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, erosion rates, and minimum required wall thickness."

The applicant also described the method used to determine the pipe wall erosion rates. The Pipe Wall Thinning Inspection Program provides for volumetric examination methods to detect loss of material by measuring component wall thickness. This measured wall loss is divided by the time the component has been in service (hours, years, etc.) to determine a conservative erosion rate. The applicant stated that this method has been used at St. Lucie in the past and has proven to be an effective method for the determination of erosion rates. The staff finds the applicant's response acceptable and considers the method used by the applicant for determining the pipe wall erosion rates reasonable and acceptable.

Acceptance Criteria: The applicant stated that the evaluation of the inspection results will consider the minimum required wall thickness in accordance with ANSI B31.7 for the Unit 1 auxiliary Feedwater piping and ASME Section III for the Unit 2 auxiliary Feedwater piping and component cooling water piping.

In RAI B.3.1.3-1, the staff requested that the applicant provide the specific section of ANSI B31.7 that will be the basis for calculating the required minimum wall thickness for Unit 1 auxiliary feedwater piping. By letter dated September 26, 2002, the applicant stated that, as indicated in Table 3.9-4 of the Unit 1 UFSAR, the auxiliary feedwater piping is designed in accordance with ANSI B31.7, "Nuclear Power Piping," Code Classes 2 and 3. The particular portion of auxiliary feedwater piping within the scope of the Pipe Wall Thinning Inspection Program is designed to ANSI B31.7, Code Class 3, requirements. Accordingly, Chapter 3-II, Part 2, "Pressure Design of Piping Components," of ANSI B31.7 will be used as a basis for calculating the required minimum wall thickness for the subject piping. The staff determined that Chapter 3-II, Part 2, of ANSI B31.7 requires the same provisions for calculating the required minimum wall thickness as United States of America Standards (USAS) B31.1.0, which has been approved by the staff.

In RAI B.3.1.3-2, the staff requested that the applicant provide the specific section in ASME Code, Section III, that will be the basis for calculating the required minimum wall thickness for the Unit 2 auxiliary feedwater piping and component cooling water piping. By letter dated September 26, 2002, the applicant stated that, as indicated in Table 9.2-4 of the Unit 2 UFSAR, the component cooling water piping is designed in accordance with ASME Section III, Class 3 requirements. Similarly, Table 10.4-1 of the Unit 2 UFSAR identifies the design code for auxiliary feedwater piping as ASME Section III, Class 2 and 3. The particular portion of the St. Lucie Unit 2 auxiliary feedwater piping within the scope of the Pipe Wall Thinning Inspection Program is designed to ASME Section III, Class 3 requirements. Accordingly, ND-3600, "Piping Design," of ASME Section III will be used as a basis for calculating the required minimum wall thickness for the subject piping. The staff finds that using ASME Section III, ND-3600, as a basis for calculating the required minimum wall thicknesses is acceptable because it meets the requirements of 10 CFR 50.55a(a)(2).

Operating Experience: The applicant stated that St. Lucie Units 1 and 2 have experienced pipe wall thinning due to erosion in the auxiliary feedwater recirculation lines and the Unit 2 control room air conditioning component cooling water return lines. In lieu of design modifications to address high fluid velocity conditions in these locations, the applicant elected to periodically inspect the susceptible lines to manage loss of material. Volumetric inspection techniques will be used to monitor these lines. The examinations will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been used previously to assess this piping condition in many other plant systems. The staff notes that operating experience identified the need for this program, and the subsequent volumetric inspections have been used to monitor susceptible lines. The staff concludes that the applicant adequately considered operating experience when it developed this new AMP.

3.0.5.2.3 UFSAR Supplement

The staff reviewed the UFSAR supplements in Appendix A to the LRA. The staff finds that the UFSAR supplements for Units 1 and 2 contain an adequate summary description of the program activities associated with the Pipe Wall Thinning Inspection Program for managing the effects of aging, as required by 10 CFR 54.21(d).

3.0.5.2.4 Conclusions

The staff finds that the Pipe Wall Thinning Inspection Program will adequately manage the aging effects so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.3 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is described in Section 3.2.2.1 of Appendix B to the LRA. This program provides aging management of the reactor coolant system (RCS) and containment spray component/commodity groups for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant demonstrated that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.3.1 Summary of Technical Information in the Application

In Section 3.2.2.1 of Appendix B to the LRA, the applicant identifies that aging management of specific RCS and containment spray component/commodity groups will be managed by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The applicant states that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with the 10 program elements of AMP XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD," as specified in NUREG-1801, Volume 2, "Generic Aging Lessons Learned (GALL) Report, Tabulation of Results," dated April 2001, with the following clarification. This program credits ASME Code Case N-509 which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie. To address aging issues of surge lines, core stabilizing lugs, and core support lugs that were identified by the staff during its review of the Turkey Point LRA, the applicant indicated that the subject program would be enhanced. The enhancements will require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and will require VT-1 visual inspections of the core stabilizing lugs and core support lugs. The commitment dates associated with enhancements to this program are contained in Appendix A to the LRA.

3.0.5.3.2 Staff Evaluation

The staff reviewed the information in Section 3.2.2.1 of Appendix B to the LRA and the summary descriptions of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program in the UFSAR supplement Sections 18.2.2.1 of Appendices A1 and A2 of the LRA. The 10 program elements in GALL AMP XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects identified for specific component/commodity groups in the reactor coolant and containment spray systems. In Appendix B, Section 3.2.2.1, to the LRA, the applicant stated that the program elements for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program are consistent with those specified in GALL AMP XI.M1 with the following clarification. This program credits ASME Code Case N-509 which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie. In addition, the enhancements, discussed above, are consistent with what the staff has accepted for previous LRA and are adequate to detect aging effects of the surge line and core stabilizing and support lugs. The applicant retains the description of the subject program, as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

The staff inspected the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M1. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff's review of the inspection findings is contained in Open Item 3.0.2.2-1. On the basis of these considerations, the staff concludes that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides an acceptable means of managing aging effects of the identified RCS and containment spray component/commodity groups. Therefore, the staff considers Open Item 3.0.2.2-1 to be closed.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the UFSAR Supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP X1.M1. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.0.5.3.3 UFSAR Supplement

Section 18.2.2.1 of Appendices A1 and A2 to the LRA provide the applicant's UFSAR supplements for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff reviewed the section to verify that the information in the UFSAR supplements provides an adequate summary of the program activities as required by 10 CFR 54.21(d). With the satisfactory resolution of Confirmatory Item 3.0.2.2-1, the staff finds the UFSAR supplements sufficient.

3.0.5.3.4 Conclusions

The staff concludes that the applicant has demonstrated that the effects of aging associated with the SCs of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.4 Boric Acid Wastage Surveillance Program

The applicant described its Boric Acid Wastage Surveillance Program in Section 3.2.4 of Appendix B to the LRA. The applicant states that the program is consistent with the 10 attributes of AMP XI.M10, "Boric Acid Corrosion," specified in the GALL report. In addition, St. Lucie credits this program for monitoring borated water systems for leakage that could potentially affect systems and components credited with a license renewal function, whereas the GALL program is limited to the RCS pressure boundary. The staff reviewed Section 3.2.4 of Appendix B to the LRA to determine whether the applicant had demonstrated that the Boric Acid Wastage Surveillance Program will adequately manage the applicable aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.4.1 Summary of Technical Information in the Application

In Section 3.2.4 of Appendix B to the LRA, the applicant states that the inspections are performed to provide reasonable assurance that borated water leakage does not lead to undetected loss of material from the reactor coolant pressure boundary (RCPB). The program will be enhanced to include those portions of the waste management system within the scope of license renewal and to inspect and calculate adjacent structures, systems, and components when leakage is identified.

This AMP was developed by the applicant in response to Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The applicant's program includes examination of primary coolant components for evidence of borated water leakage that could degrade the external surfaces of nearby SCs and implementation of corrective actions to address coolant leakage. At a minimum, these activities are performed inside containment at the beginning and end of each refueling outage.

The following systems and structures contain commodities/components for which this AMP is credited with managing the aging effect of loss of material.

<u>Systems</u>

- chemical and volume control
- component cooling water
- containment cooling
- containment isolation
- containment spray
- containment post accident monitoring
- fire protection
- fuel pool cooling
- instrument air
- intake cooling water
- main Feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine
- miscellaneous bulk gas supply
- primary makeup water
- reactor coolant
- safety injection

- sampling
- service water
- ventilation
- waste management

<u>Structures</u>

- containment
- fuel handling building
- reactor auxiliary building
- yard structures

The applicant states that the Boric Acid Wastage Surveillance Program is consistent with the 10 program elements of AMP XI.M10, "Boric Acid Corrosion," as specified in the GALL Report dated April 2001. The existing program will be enhanced prior to the end of the current license term. The applicant states that commitment dates associated with enhancements to this AMP are contained in Appendix A to the LRA.

3.0.5.4.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.4 of Appendix B to the LRA and the summary description of the Boric Acid Wastage Surveillance Program in the UFSAR supplement, Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 to the LRA. The 10 program elements in GALL AMP XI.M10, "Boric Acid Corrosion," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage the aging effects in RCS components. In Appendix B, Section 3.2.4, to the LRA, the applicant stated that the program elements for the Boric Acid Wastage Surveillance Program are consistent with those specified in AMP XI.M10 of the GALL Report. The applicant retains the program description of the Boric Acid Wastage Surveillance Program, as well as the descriptions of the program's 10 elements, on record at the St. Lucie Nuclear Station.

The staff inspected the Boric Acid Wastage Surveillance Program for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M10. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The inspection report is attached to this SER for further inspection details. The inspection found that the Boric Acid Wastage Surveillance Program provides an acceptable means of managing the aging effects induced by boric acid corrosion in RCS components.

The staff finds this AMP acceptable because the program has been effectively managing aging effects in all applicable SSCs constructed of carbon steel, low-alloy steel, and other susceptible materials that may be affected by borated water leakage.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M10 in the UFSAR supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP X1.M10. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

The applicant credits this program with monitoring borated water systems for leakage that could potentially affect systems and components credited with a license renewal function (in addition to systems and components inside the RCS pressure boundary). The staff's review of the Boric Acid Wastage Surveillance Program includes the applicant's operating experience regarding how the program manages aging effects in systems and components beyond the RCS pressure boundary.

The applicant states that the Boric Acid Wastage Surveillance Program has been an ongoing program since the 1980s. The program was implemented to manage aging effects for systems consistent with AMP XI.M10 in the GALL Report and for systems and structures included within the scope of license renewal as specified in Section 3.0.5.4.1 of this SER. A review of the operating experience by the applicant showed that, since the establishment of this program, there have not been any instances of boric acid corrosion that impacted license renewal system intended functions.

NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," was issued as a result of reactor pressure vessel head wastage that occurred due to a control rod drive mechanism (CRDM) nozzle cracking at the Davis Besse Nuclear Power Plant. The plant identified severe degradation of the reactor vessel head (RVH) due to exposure to concentrated boric acid. To date, all licensees have responded to the bulletin, providing information about their boric acid corrosion control (BACC) programs, as well as to the RAI that was issued on September 26, 2002. This information has been reviewed to assess plant-specific compliance with NRC regulations. This information will also be used by the NRC staff to determine the need for, and to guide the development of, additional regulatory actions to prevent degradation of the RCPB. Because this is an emerging issue that has not yet been resolved, it will be resolved during the current license term. Consideration of this issue is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

3.0.5.4.3 UFSAR Supplement

Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 to the LRA provide the applicant's UFSAR supplements for the Boric Acid Wastage Surveillance Program. The staff reviewed Section A1, Chapter 18.2.4, and Section A2, Chapter 18.2.3, of the UFSAR supplement and found that the description of the applicant's Boric Acid Wastage Surveillance Program is consistent with Section B.3.2.4 of the LRA. The staff identified that the applicant needs to modify the UFSAR supplement descriptions of the Boric Acid Wastage Surveillance Program to include portions of the waste management system within the scope of license renewal. The staff generated Confirmatory Item 3.0.5.4-1 to track this item.

In its March 28, 2003, response to Confirmatory Item 3.0.5.4-1, the applicant indicated that it will modify the UFSAR supplement descriptions of the Boric Acid Wastage Surveillance Program to include portions of the waste management system. This enhancement will be completed prior to the end of the initial operating license term for each unit. Therefore, the staff considers Confirmatory Item 3.0.5.4-1 to be closed.

3.0.5.4.4 Conclusion

The staff concludes that the applicant has demonstrated that the effects of aging associated with the SCs of the Boric Acid Wastage Surveillance Program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.5 Chemistry Control Program—Water Chemistry Control Subprogram

The Chemistry Control Program—Water Chemistry Control Subprogram is described in Section 3.2.5.1 of Appendix B to the LRA. This program provides aging management of piping and associated SCs exposed to treated water for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Chemistry Control Program—Water Chemistry Control Subprogram will adequately manage the applicable aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.5.1 Summary of Technical Information in the Application

In Section 3.2.5.1 of Appendix B to the LRA, the applicant states that aging effects will be managed by the Water Chemistry Control Subprogram to ensure that significant degradation is not occurring and that the component intended function will be maintained during the period of extended operation.

The applicant states that the Water Chemistry Control Subprogram has been an ongoing program at St. Lucie since the initial startup and has evolved over many years of plant operation. The program provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished by effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. The applicant further states that chemistry data are also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect component intended functions.

The applicant states that the Water Chemistry Control Subprogram is consistent with the 10 program elements of AMP XI.M2, "Water Chemistry," as specified in the GALL Report, except that no special one-time inspection is required.

3.0.5.5.2 Staff Evaluation

The staff reviewed the information in Section 3.2.5.1 of Appendix B to the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions of the program in the UFSAR supplement (Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 to the LRA). The 10 program elements in GALL AMP XI.M2, "Water Chemistry," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects of components in a fluid environment to minimize corrosion. In Appendix B, Section 3.2.5.1, to the LRA, the applicant has stated that the program elements for the Water

Chemistry Control Subprogram are consistent with those specified in AMP XI.M2 of the GALL Report, except that no special one-time inspection is required. The applicant retains the program description of the Water Chemistry Control Subprogram, as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

In a discussion of operating experience, the applicant stated that no special one-time inspection will be performed for the purpose of verifying the effectiveness of the Water Chemistry Control Subprogram. This position deviates from the GALL Report as it recommends the one-time inspection. However, the applicant stated that internal surfaces of components are visually inspected for loss of material and other aging effects during routine and corrective maintenance requiring equipment disassembly.

By letter dated July 18, 2002, the staff issued RAI B.3.2.5-1. The RAI requested the applicant to clarify that those locations inspected during routine and corrective maintenance include representative susceptible locations (such as low-flow or stagnant areas). In addition, the applicant was asked to discuss past findings that demonstrated that routine and corrective maintenance verified the effectiveness of the Water Chemistry Control Subprogram.

In its response dated September 26, 2002, the applicant stated that routine preventive and corrective maintenance inspections do not specifically target components subject to low flow or other susceptible areas. However, the susceptible areas, such as low-flow areas and crevices associated with mechanical joints, will be exposed during the process of disassembling and be subject to inspection. Data and results from these inspections are documented. The ASME Boiler and Pressure Vessel Code, Section XI requires an internal visual examination to determine the condition of Class 1 valve and pump internals at least once each inspection interval. The applicant stated that when significant corrosion or degraded parts are identified, the support of materials experts within FPL is typically requested to determine root cause. The applicant further stated that a review of plant-specific operating experience for the St. Lucie closed water systems had been performed to identify any age-related material failures associated with crevice corrosion or inadequate chemistry controls.

No instances of crevice corrosion in treated water systems or evidence of an ineffective Water Chemistry Control Subprogram were identified. This review included past material failures associated with various components, including several in stagnant or low-flow areas (vent and drain lines and instrument lines). None of the failures associated with stagnant or low-flow lines was attributed to crevice corrosion or lack of chemistry controls.

The applicant has had a Water Chemistry Control Subprogram since initial plant startup. Susceptible areas are routinely inspected during preventive and corrective maintenance under this program, which is comparable to a one-time inspection. In addition, the applicant's review of operating experience did not identify any evidence of an ineffective Water Chemistry Control Subprogram. Therefore, based on the above inspections of susceptible areas and operating experience, the staff finds the applicant's response to RAI B.3.2.5-1 adequate to resolve the issue.

The staff inspected the Water Chemistry Control Subprogram for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M2. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. On the basis of these considerations, the staff concludes that the Water

Chemistry Control Subprogram provides an acceptable means of managing aging effects for components exposed in a fluid environment.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M2 in the UFSAR supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP X1.M2. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.0.5.5.3 UFSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 to the LRA provide the applicant's UFSAR supplement for the Chemistry Control Programs at St. Lucie. The staff reviewed the sections to verify that the information in the UFSAR supplements provides an adequate summary of the program activities as required by 10 CFR 54.21(d). With the successful resolution of Confirmatory Item 3.0.2.2-1, the staff finds the UFSAR supplements to be sufficient.

3.0.5.5.4 Conclusions

The staff concludes that the applicant has demonstrated that the effects of aging associated with the SCs of the Water Chemistry Control Subprogram will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.6 Chemistry Control Program—Closed-Cycle Cooling Water System Chemistry Subprogram

The Chemistry Control Program—Closed-Cycle Cooling Water System Chemistry Subprogram is described in Section 3.2.5.2 of Appendix B to the LRA. This program provides aging management of piping and associated components for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Chemistry Control Program—Closed-Cycle Cooling Water System Chemistry Subprogram will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.6.1 Summary of Technical Information in the Application

In Section 3.2.5.2 of Appendix B to the LRA, the applicant states that aging effects will be managed by the Closed-Cycle Cooling Water System Chemistry Subprogram to ensure that significant degradation is not occurring and that the component intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram has been an ongoing program at St. Lucie since the initial startup and has evolved over many years of plant operation. The program provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished by effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. The applicant further states that chemistry data are also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect the component intended functions.

The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the 10 program elements of AMP XI.M21, "Closed-Cycle Cooling Water System," as specified in the GALL Report, except for surveillance testing and inspection.

3.0.5.6.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.5.2 of the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions of the Chemistry Control Program in the UFSAR supplement (Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 to the LRA). The 10 program elements in GALL AMP XI.M21, "Closed-Cycle Cooling Water System," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects of components in a fluid environment to minimize corrosion. In Appendix B, Section 3.2.5.2, to the LRA, the applicant has stated that the program elements for the Closed-Cycle Cooling Water System Chemistry Subprogram are consistent with those specified in AMP XI.M21 of GALL, except for surveillance testing and inspection. The applicant retains the program description of the Closed-Cycle Cooling Water System Chemistry Subprogram, as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

The applicant credits the St. Lucie Water Chemistry Control Program—Closed-Cycle Cooling Water System Subprogram for managing loss of material due to general, pitting, and crevice corrosion in the cooling water system components exposed to treated water. These components are made of carbon steel, stainless steel, cast iron, and aluminum bronze. The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the 10 attributes of AMP X1.M21, "Closed-Cycle Cooling Water System," in the GALL Report, with the exception that this subprogram does not address surveillance testing and inspection. The applicant further states that the St. Lucie Intake Cooling Water System Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program. However, the Intake Cooling Water System Inspection Program includes inspection of only those closed cooling water (CCW) system components that are exposed to raw water, and not to treated water, which include the CCW heat exchanger tubes, tubesheets, channels, and doors. The GALL Report recommends inspecting these components and other CCW system components that are exposed to treated water and are susceptible to loss of material. By letter dated July 18, 2002, the staff requested, in RAI B.3.2.5-2, the applicant to provide justification for not including inspection in the aging management of the CCW components exposed to treated water.

In its response dated September 26, 2002, the applicant stated that a review of St. Lucie plant-specific operating experience was performed as part of the AMR process for the CCW System to identify any age-related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective Chemistry Control Program.

The applicant noted that many CCW components have been inspected in the past as part of corrective maintenance or the Periodic Surveillance and Preventive Maintenance Program (e.g., periodic pump overhauls). The applicant further stated that during the past 12 months, more than 30 maintenance work orders were generated for Units 1 and 2 CCW that required disassembly or removal of components. These work orders included repairs on instrumentation and other isolation valves, flow control valves, and check valve and relief valve internal inspections throughout the system. A majority of these components (e.g., relief and isolation valves) entailed system locations where stagnant flow conditions exist. These locations are the likely candidates for pitting corrosion. The internal condition of the components has provided additional confidence that the Closed-Cycle Cooling Water System Chemistry Subprogram is effective.

The applicant stated that the St. Lucie maintenance procedures typically specify inspection criteria or reference plant quality instructions that specify internal cleanliness requirements. As an example, the maintenance procedure for relief valve removal and testing includes a visual inspection of valve and piping mating surfaces for corrosion and pitting. Additionally, the applicant referred to the response to RAI 3.3.2-1 for additional information regarding maintenance inspection requirements. The response to RAI 3.3.2-1 stated that the maintenance procedures specify Class C cleanliness requirements for CCW. Class C permits a tightly adhered oxide film or red oxide coating, as well as small areas of light rust, but pitting is not acceptable. The applicant further stated that any significant degradation identified during these inspections would have been documented under the plant's Corrective Action Program. Therefore, the applicant concluded that the Closed-Cycle Cooling Water System Chemistry Subprogram is an effective program, and additional inspections of other CCW components specifically to confirm program effectiveness are unnecessary.

On the basis of its review, the staff finds that the applicant's response to RAI B.3.2.5-2 clarifies and satisfactorily resolves the item because (1) some of the CCW component locations with stagnant flow conditions that might be susceptible to pitting corrosion were included in the past maintenance activities, (2) the connections between metals and nonmetals (e.g., flange connections associated with valves and pumps) that might be susceptible to crevice corrosion were also included in the maintenance activities, and (3) no loss of material (corrosion damage) has been detected during activities to verify the effectiveness of the Closed-Cycle Cooling Water System Chemistry Subprogram.

The staff inspected the Closed-Cycle Cooling Water System Chemistry Subprogram for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M21. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. On the basis of these considerations, the staff concludes that the Closed-Cycle Cooling Water System Chemistry Subprogram provides an acceptable means of managing aging effects for components exposed in a fluid environment.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M21 in the UFSAR supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP X1.M21. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.0.5.6.3 UFSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 to the LRA provide the applicant's UFSAR supplements for the Chemistry Control Programs at St. Lucie. The staff reviewed the sections to verify that the information in the UFSAR supplements provides an adequate summary of the program activities as required by 10 CFR 54.21(d). With the satisfactory resolution of Confirmatory Item 3.0.2.2-1, the staff finds the UFSAR supplements sufficient.

3.0.5.6.4 Conclusions

The staff concludes that the applicant has demonstrated that the effects of aging associated with the SCs of the Closed-Cycle Cooling Water System Chemistry Subprogram will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.7 Fire Protection Program

The Fire Protection Program is described in Section 3.2.8 of Appendix B to the LRA. This program provides aging management for the fire protection system and fire-rated assemblies. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Fire Protection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.7.1 Summary of Technical Information in the Application

As identified in Chapter 3 of the LRA, the Fire Protection Program is credited for aging management of specific component/commodity groups in the fire protection system and the fire-rated assemblies.

This program is plant specific. The GALL Report contains two AMPs, XI.M26, "Fire Protection," and XI.M27, "Fire Water System." The St. Lucie Fire Protection Program combines the appropriate scope of the two GALL programs. In addition, FPL credits the Systems and Structures Monitoring Program, the Galvanic Corrosion Susceptibility Inspection Program, and the Boric Acid Wastage Surveillance Program for managing aging of the appropriate components of the fire protection system and fire-rated assemblies. Concrete and steel structural components that serve as fire barriers are addressed with their associated structure, as appropriate.

3.0.5.7.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.8 of Appendix B of the LRA; the applicant's September 26, 2002, response to the staff's RAIs; the applicant's November 27, 2002, letter providing supplements to its September 26, 2002, letter; and the UFSAR summary description of the Fire Protection Program in Appendix A to the LRA. As identified in Tables

3.3-6 and 3.5-8 of the LRA, the Fire Protection Program is credited for aging management of specific component/commodity groups associated with the fire protection system and fire-rated assemblies. The staff evaluated the program against 10 elements that are described in Appendix A to NUREG-1800—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Fire Protection Program is credited for managing the aging effects of loss of material due to corrosion (including selective leaching) of the mechanical components of the fire protection system within the scope of license renewal. The mechanical components include valves (bodies only) and pumps (casings only), tanks, orifices, filters, piping, tubing, sprinkler heads, flexible hoses, haloed system components, fire hydrants, vortex breakers, and sight glasses. The LRA states that the program is also credited for managing loss of material due to corrosion of fire doors. The staff finds the scope of the Fire Protection Program acceptable because it covers the applicable aging effects for the components of the fire protection system and fire-rated assemblies.

Preventive Actions: Mechanical fire protection system components are periodically flushed, performance tested, and inspected. Many fire protection system components are provided with a protective coating to minimize the potential for external degradation. Although not credited for eliminating aging effects, coating minimizes corrosion by limiting exposure to the environment. The staff finds the preventive actions identified above adequate and acceptable.

Parameters Monitored or Inspected: The LRA states that surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material. Internal conditions are monitored through the use of leakage, flow, and pressure testing. Internal loss of material can be detected by changes in flow or pressure, leakage, or evidence of excessive corrosion products during flushing of the system.

In RAI B3.2.8-2, the staff requested that the applicant provide the extent of inspection for each type of penetration seal and the frequency of inspections and functional tests of the fire doors and seals. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant provided the following response.

> As stated in the response to RAI 3.5-3, and based on the information in SECY-96-146 and St. Lucie plant-specific operating experience, fire barrier penetration seals do not experience aging effects that would lead to a loss of intended function. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.
>
> However, plant procedures do provide for the inspection of penetration seals. Currently, visual inspection of at least 10% of each type of sealed penetration is performed during each refueling outage. If changes in appearance or degradations are found, a visual inspection of an additional 10% of each type is made. The types of penetrations are defined as:
>
> (1) Mechanical penetration seals
> (2) Electrical penetration seals
> (3) Instrumentation penetration seals

(4) Heating and Ventilation penetration seals

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

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

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

Fire door inspection is currently conducted every six months.

The applicant's response satisfactorily addresses the staff's concerns, and the RAI issues are considered resolved. The staff finds that the parameters monitored will permit timely detection of the aging effects and are therefore acceptable.

Detection of Aging Effects: The LRA states that the detection of age-related degradation on external surfaces is determined by visual examination. Surfaces of SCs are examined for coating degradation, rust, damage, deterioration, leakage, or corrosion. Functional testing and flushing of the system clear away internal scale and corrosion products that could lead to blockage or obstruction. Flow and pressure tests verify system integrity. Visual examinations of internal portions of the system, when opened, also verify unobstructed flow and integrity of the piping and components.

In RAI B.3.2.8-1, the staff requested that the applicant provide justification for excluding loss of material due to micro biologically influenced corrosion (MIC) or biofouling of carbon steel and cast-iron components in fire protection system exposed to water. In addition, the staff requested that the applicant clarify its position that the Fire Protection Program is consistent with the corresponding programs in the GALL Report. By letter dated September 26, 2002, the applicant provided the following response.

Loss of material due to micro biologically influenced corrosion (MIC) has not been excluded as an aging effect requiring management for carbon steel and cast-iron components in fire protection systems. As discussed in LRA Appendix C, Section 5.1 (page C-13), MIC was considered an aging mechanism which causes loss of material for systems operating at temperatures less than 210 °F and pH less than 10. As a result, the aging management review of the fire protection system identified loss of material due to MIC as an aging effect requiring management for the internal surfaces of the cast iron and carbon steel components exposed to "Raw water-city water." Loss of material due to this aging mechanism is included on LRA Table 3.3-6 (pages 3.3-42 through 3.3-44).

With respect to biofouling, as stated in LRA Appendix C, Section 5.3 (page C-15), biofouling is an aging effect due to an accumulation of macro-organisms. Fire Protection at St. Lucie uses water classified as "Raw water-city water." As stated in LRA Appendix C, Section 4.1.2 (page C-7), this water is potable water -- water that has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. Macro-organisms would not be found in water. Therefore, biofouling is not an aging effect requiring management.

LRA Subsection 3.3.4 (page 3.3-11) incorrectly stated that the Fire Protection Program is consistent with the corresponding programs in the GALL Report. As stated in LRA Appendix B

Section 3.2.8 (page B-39), the Fire Protection Program is plant-specific. Therefore, the list in LRA Subsection 3.3.4 (page 3.3-11) is revised to delete the Fire Protection Program from the list of St. Lucie programs that are consistent with the corresponding programs in the GALL Report, and revised to add the Fire Protection Program to the St. Lucie plant-specific programs list.

The applicant's response satisfactorily addresses the staff's concerns and the RAI issues are considered resolved.

In RAI B.3.2.8-3, the staff asked the applicant to discuss its program for internal inspections of the fire protection piping, and to explain how the program will detect wall thinning due to internal corrosion. Since opening the system results in the introduction of oxygen that may contribute to the initiation of general corrosion, the applicant was asked to explain why nonintrusive means of measuring wall thickness, such as ultrasonic inspection, are not used to manage this aging effect. The applicant responded to RAI B.3.2.8-3 by letters dated September 26, 2002, and November 27, 2002, stating that the internal loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. The applicant also stated that St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable. The staff found that the applicant had not satisfactorily explained the monitoring of the internal corrosion in the piping that is not subject to flow tests, therefore the staff generated Open Item 3.0.5.7-1.

By letter dated March 28, 2003, the applicant provided the following information related to wall thinning due to internal corrosion of stagnant piping systems.

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

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

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

During the recent implementation of Fire Water System modifications, ultrasonic pipe wall thickness measurements were taken on stagnant portions of the system, which confirm the good internal condition of the fire main and its branches. These modifications were associated with enhancements identified prior to or during the 1998 NRC Fire Protection Functional Inspection, and included the addition of an automatic suppression system for Thermo-Lag walls and the addition of new hose stations in the Reactor Auxiliary Buildings. Pipe wall thickness measurements were taken on 4 and 6 inch normally stagnant lines prior to welding and confirmed that minimal internal loss of material due to corrosion has taken place (i.e., the pipe wall thicknesses were approximately nominal). Based upon the nominal pipe wall thickness and the measured values for the limiting case, the corrosion rate over 24 years of service is calculated to be approximately 0.3 mils/year. Additionally, if the original pipe wall thickness is conservatively assumed to be nominal plus the manufacturer's fabrication allowance (i.e., +12.5%), the worst case corrosion rate is calculated to be 1.5 mils/year. Based upon this worst case corrosion rate and the measured pipe wall thickness, the projected pipe wall thickness at the end of the extended operating period is 175 mils, well in excess of the ANSI B31.1 Code required minimum wall of 22 mils. Thus, additional pipe wall thickness measurements are not required and the current methods of monitoring internal conditions are adequate and reliable.

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

The staff concludes that the applicant's position is consistent with the interim staff guidance ISG-4, "Aging Management of Fire Protection Systems for License Renewal," and the aging management program that the staff approved for Turkey Point, Units 3 and 4. On the basis of the results of the volumetric inspection and the analysis, the staff concludes that the applicant has adequately addressed the internal corrosion of stagnant portions of the fire protection system piping. The staff considers Open Item 3.0.5.7-1 closed.

On the basis of the identified surveillance tests, the quality of the water used in the system, and the results of volumetric inspections and analysis of small bore piping in stagnant portions of the fire protection system, the staff concludes that the detection of aging effects attribute is adequate to ensure the identification of degradation of the fire protection system components.

Monitoring and Trending: The LRA states that administrative procedures contain the regulatory commitments and surveillance requirements for the Fire Protection Program. The procedures governed by the Fire Protection Program require various testing, inspection, or surveillance frequencies. The frequency and scope of the testing, inspection, or surveillance associated with the Fire Protection Program are sufficient to identify effects of aging prior to their compromising the integrity of the system or its intended function.

In RAI B.3.2.8-4, the staff asked the applicant to discuss the inspection activities that provide the reasonable assurance that the intended function of below-grade fire protection piping will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant stated that internal and external conditions for below-grade fire protection piping are monitored via leakage, flow, and pressure testing. Internal and external loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable for fire protection system underground piping. The staff finds the applicant's response reasonable and acceptable and consistent with the staff position.

The staff finds that the applicant's methodology will provide effective monitoring and trending and is therefore acceptable.

Acceptance Criteria: The LRA states that the results of the testing, inspection, or surveillance will be evaluated in accordance with the acceptance criteria in the appropriate fire protection procedure(s). Degradation found as a result of the testing, inspection, or surveillance of the systems or components is entered into the Corrective Action Program.

In RAI B.3.2.8-6, the staff asked the applicant to discuss the inspection plans for the sprinkler system during the current operating term, as well as during the extended period of operation. By letter dated November 27, 2002, the applicant provided the following response.

> For St. Lucie Unit 1, the oldest sprinkler heads were installed approximately one year prior to issuance of the St. Lucie Unit 1 Facility Operating License. Per St. Lucie Units 1 and 2 UFSARs, Appendix 9.5A, the St. Lucie Current Licensing Basis does not include NFPA25 for testing and inspection of sprinkler heads; however, St. Lucie generally conforms to NFPA guidelines. St. Lucie uses city water (potable) as its water source for the fire protection system. This water was conservatively classified as "raw water" for the purpose of performing aging management reviews even though it is clean and free of contaminants compared to lake or river water used in fire protection systems at other plants. The quality of the water minimizes loss of material, as evidenced by St. Lucie's operating and maintenance experience. A fire protection system annual flush is credited for ensuring the system is clear of scale, debris and foreign material.
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> For dry pipe closed head sprinkler systems, procedures verify the systems are in a state of readiness by ensuring proper operation of clapper/inlet valves, all nozzles are unobstructed, and that water and supervisory nitrogen pressure is available.
>
> For wet pipe closed head sprinkler systems, a procedure verifies that the system alarm functions and checks for water clarity.
>
> The results of a review of plant-specific operating history associated with the tests and inspections of these components did not identify any degraded conditions for the internal surfaces of these sprinklers.
>
> Based on feedback from meetings with NRC staff conducted during the review of the Turkey Point Unit 3 and 4 LRA review, and open items identified on previous license renewal applications, St. Lucie proposes to perform testing of wet pipe sprinkler heads following the guidance of NFPA 25 commencing in the year 2026 (50 years from the issuance of the original operating license on Unit 1). This enhancement will be included within the Fire Protection Program (LRA Appendix B Subsection 3.2.8, page B-39).

Considering the above, the staff finds that the testing of sprinkler heads will provide reasonable assurance that the sprinkler heads will be able to perform their intended function. The staff finds the acceptance criteria reasonable and acceptable.

Operating Experience: The LRA states that the Fire Protection Program has been an ongoing program at St. Lucie, Units 1 and 2. This program was enhanced by implementation of 10 CFR 50, Appendix R, and has evolved over many years of plant operation. The program incorporates the best practices recommended by the National Fire Protection Association (NFPA) and Nuclear Electric Insurance Limited (NEIL) and is approved by the NRC. The Fire Protection Program has been significantly enhanced since initial plant operation and has been effective at maintaining fire protection features by reliable performance.

The LRA further states that the overall effectiveness of the Fire Protection Program is demonstrated by the excellent operating experience of SSCs that are influenced by the Fire Protection Program. The Fire Protection Program has been subject to periodic internal assessment activities. These activities, as well as other external assessments, help to maintain highly effective fire protection control and facilitate continuous improvement through monitoring industry initiatives and trends in the area of aging management.

In RAI B.3.2.8-5, the staff asked the applicant to discuss the significant recent enhancements that resulted from these assessments, and to indicate whether or not these enhancements have received NRC approval. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant provided the following response.

> There have been no recent enhancements to the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39). However, based on recent periodic internal and external assessments, fire protection plant modifications have been implemented including the replacement of all Unit 2 preaction suppression system local control panels with updated equipment, replacements of Unit 1 smoke detectors with new model detectors, replacement of both Control Room fire computers with new fire panels, extended preaction system coverage in the Units 1 and 2 cable loft areas, and upgraded penetration seals (cable tray fire stops) in Unit 2. St. Lucie Unit 1 UFSAR Appendix 9.5A and Unit 2 UFSAR Chapter 9.5A Fire Protection Program Report contain a review of Fire Protection and the Fire Protection Program with respect to the applicable codes and standards.
>
> As a result of NRC Generic Letter 92-08, corrective actions associated with Thermo-lag were initiated. The Thermo-lag corrective actions were completed and the NRC was notified (see R. S. Kundalkar (FPL) letter to NRC Document Control Desk, L-2000-83, St. Lucie Unit 1 Thermo-Lag 330-1 Summary Report, April 7, 2000 and J. A. Stall (FPL) letter to NRC Document Control Desk, L-98-165, St. Lucie Unit 2 Thermo-Lag 330-1 Summary Report, June 23, 1998).
>
> St. Lucie also performed NFPA Code reviews of the suppression and detection systems, and, based on the findings, further evaluations and modifications were implemented (e.g., increased radiant heat shield coverage in Unit 1 and 2 Containments and improved weather resistance of exterior smoke detection systems). The NRC reviewed some of the evaluations and modifications described above during the St. Lucie Fire Protection Functional Inspection conducted in 1998 (NRC Inspection Report Nos. 50-335/98-14, 50-389/98-14). Others have been implemented subsequent to this inspection. With respect to NRC review, all changes to the Fire Protection Program and/or system are reviewed in accordance with 10 CFR 50.59 and Facility Operating Licenses DPR-67 (Unit 1) Section C.(3) and NFP-16 (Unit 2) Section C.3.20.

The applicant's response satisfactorily addresses the staff's concerns, and the RAI is considered resolved. The staff finds that, based on the operating experience, there is reasonable assurance that the applicant will maintain the fire protection system during the extended period of operation.

3.0.5.7.3 UFSAR Supplement

The staff reviewed the UFSAR supplements in Appendix A of the LRA. The staff concludes that the information provided in the UFSAR supplements is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of program activities, as required by 10 CFR 54.21(d).

3.0.5.7.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with the Fire Protection Program will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.8 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program is described in Section 3.2.9 of Appendix B to the LRA. This program provides aging management of the steam generator (SG) nozzles and piping in the main Feedwater system, condensate system, heater drains and vents system, main steam system, and SG blowdown system for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Flow-Accelerated Corrosion Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.8.1 Summary of Technical Information in the Application

In Section 3.2.9 of Appendix B to the LRA, the applicant identified the Flow- Accelerated Corrosion Program to manage the aging effects of systems and components subject to flow-accelerated corrosion (FAC). FAC reduces pipe wall thickness due to the movement of steam or water in the pipe. Industry experience has shown that FCA has affected SG nozzles and piping in the main Feedwater system, condensate system, extraction steam system, moisture separation reheater system, and Feedwater heater drain system.

The applicant stated that the Flow-Accelerated Corrosion Program is consistent with the 10 attributes of AMP XI.M17, "Flow-Accelerated Corrosion," as specified in the GALL Report. The Flow-Accelerated Corrosion Program has been an ongoing program at St. Lucie since the 1980s. The program was originally implemented as a result of steam leaks experienced in the industry, including at St. Lucie. The applicant formalized its Flow -Accelerated Corrosion Program in response to NRC GL 89-09, "Flow Accelerated Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants." The applicant continuously upgrades the Flow-Accelerated Corrosion Program on the basis of industry experience and research.

3.0.5.8.2 Staff Evaluation

The staff reviewed the applicant's Flow-Accelerated Corrosion Program to determine whether the applicant has demonstrated that the aging effects on the systems and components caused by FAC will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff focused its evaluation on how the Flow-Accelerated Corrosion Program manages aging effects through the effective incorporation of the 10 elements shown in GALL AMP XI.M17 (program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant has credited the Flow-Accelerated Corrosion Program at St. Lucie for aging management of systems and components including main steam, auxiliary steam and turbine, main Feedwater, SG blowdown, and SG nozzles of the RCA. In addition, the applicant will enhance the program to include small bore piping associated with selected steam traps and drain lines that are potentially susceptible to FAC and external general corrosion. The applicant periodically examines various sections of susceptible piping to determine the effects of flow accelerated corrosion. Piping that is affected by flow accelerated corrosion is either repaired or replaced. Branch connections are examined as St. Lucie or industry experience requires. The applicant has generated condition reports for piping wall thicknesses that have been found to be below the screening criteria in the Flow-Accelerated Corrosion Program. Since 1996, the applicant has replaced a small number of components due to FAC, including main steam small bore piping, steam trap piping, and SG blowdown piping in Unit 1, and SG blowdown system piping in Unit 2.

The applicant has implemented the Flow-Accelerated Corrosion Program in accordance with the Electric Power Research Institute (EPRI) guidelines provided in NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program." The applicant has committed to complete the enhancement of the Flow Accelerated Corrosion Program prior to the end of the initial operating license term for Units 1 and 2. This commitment is documented *in Section 18.2.9 of the Unit 1 UFSAR supplement and Section 18.2.8 of the Unit 2 UFSAR* supplement. The applicant retains the program description of the Flow-Accelerated Corrosion Program, as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

The staff inspected the Flow-Accelerated Corrosion Program for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M17. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. On the basis of these considerations, the staff concludes that the Flow-Accelerated Corrosion Program provides an acceptable means of managing aging effects of components subject to FAC.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M17 in the UFSAR supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplements descriptions to include references to GALL AMP X1.M17. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.0.5.8.3 UFSAR Supplement

Section 18.2.9 of Appendix A1 and Section 18.2.8 of Appendix A2 to the LRA provide the applicant's UFSAR supplements for the Flow-Accelerated Corrosion Program. The staff reviewed the sections to verify that the information in the UFSAR supplements provides an adequate summary of the program activities, as required by 10 CFR 54.21(d). With the satisfactory resolution of Confirmatory Item 3.0.2.2-1, the staff finds the UFSAR supplements sufficient.

3.0.5.8.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with components subject to FAC will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.0.5.9 Periodic Surveillance and Preventive Maintenance Program

The applicant described its Periodic Surveillance and Preventive Maintenance Program in Section 3.2.11 of Appendix B to the LRA. The staff reviewed this section of the application to determine whether the applicant had demonstrated that the aging effects on applicable systems and structures will be adequately managed by this program during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.9.1 Summary of Technical Information in Application

The applicant specified that the Periodic Surveillance and Preventive Maintenance Program applies to component/commodity groups in certain designated systems and structures. The program is intended for managing the aging effects of loss of material, cracking, fouling, loss of seal, and embrittlement of systems and structures. Activities of the program consist of periodic visual inspection of selected surfaces of specific components and structural components, or alternatively, their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program also includes leak inspections of the emergency diesel generator exhaust system.

As identified in Appendix B, Section 3.2.1.1 to the LRA, the Periodic Surveillance and Preventive Maintenance Program is credited for aging management of specific component/commodity groups in the following systems and structures.

<u>Systems</u>

- chemical and volume control
- intake cooling water
- containment cooling
- main feedwater and steam generator blowdown
- containment spray
- primary makeup water
- diesel generator and support systems
- service water
- emergency cooling canal
- ventilation
- instrument air

<u>Structures</u>

- containments
- fuel handling buildings
- reactor auxiliary buildings

The applicant indicated that the Periodic Surveillance and Preventive Maintenance Program is an established program and its effectiveness has been demonstrated by the improved systems and structures material condition and reliability. The applicant concludes that the program will provide reasonable assurance that the systems and components within the scope of license renewal will be maintain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(d).

3.0.5.9.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.11 of Appendix B to the LRA; the applicant's September 26, 2002, and supplemental November 27, 2002, responses to the staff's RAIs; and the summary description of the Periodic Surveillance and Preventive Maintenance Program in Appendix A to the LRA. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that component intended function will be maintained consistent with the CLB throughout the period of extended operation for systems and structures included in the program. The staff evaluated the program against the 10 elements described in Appendix A to NUREG-1800 (program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Periodic Surveillance and Preventive Maintenance Program is credited for managing the aging effects of loss of material, loss of seal, fouling (mechanical components only), and cracking of the component/commodity groups in the systems and structures listed above. The scope of the program provides for visual inspection and examination of surfaces of SSCs. Additionally, the program provides for replacement or refurbishment of certain components on a specified frequency, as appropriate, and periodic sampling and water removal from hydraulic accumulators and diesel fuel oil storage tanks. The staff finds that the relevant systems and structures are included in the scope of the program and therefore the scope is adequate.

Preventive Actions: The LRA states that the preventive measures include charging pump block internal inspections for Unit 2 only, oil sampling, and water removal and replacement of specific structural components and component groups based on operating experience. However, the applicant provided limited information regarding the different attributes of the Periodic Surveillance and Preventive Maintenance Program related to aging management of the instrument air system components. In RAI B3.2.11-2, the staff asked the applicant for the following information.

(1) Provide information about whether the program is based on the Instrument Society of America's Standard ISA-S7.0.1-1996, "Quality Standards for Instrument Air." Specifically,

discuss whether the moisture content and particulate size in the instrument air are continuously monitored. In addition, provide the acceptance criteria for particulate size and oil content in the instrument air, how often the system is sampled to ensure that air quality is maintained.

(2) Provide information about the inspection and testing frequency used for the instrument air system components. Also, verify and indicate whether or not the program follows the recommendations made by the industry report issued by the Electric Power Research Institute (EPRI) as EPRI NP-7079, "Instrument Air Systems–A Guide for Power Plant Maintenance Personnel," 1990, or its 1998 revision (i.e., EPRI/NMAC TR-108147, 1998).

By letter dated September 26, 2002, the applicant provided the following response to item 1.

> Instrument Air at St. Lucie was redesigned in the late 1980s to address equipment related problems and industry issues identified by GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment." These modifications included the replacement of the instrument air dryers with more effective desiccant dryers (including prefilter and after filters) and two new air compressors per unit with capacities and purification capabilities recommended by ANSI/ISA-S7.3, "Quality Standard for instrument Air, Instrument Society of America." Instrument Air for St. Lucie Units 1 and 2 meets the air quality requirements of ANSI/ISA S7.3-1975, Quality Standard for Instrument Air.
>
> The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) is not based on the Instrument Society of America's Standard ISA S7.0.1-1996. Although the moisture content and particulate size in Instrument Air are not continuously monitored, performance of the air dryers is monitored regularly via a dryer moisture indicator. The dryers are reconditioned as needed based on this indication. The instrument air compressors are of the oil-free type. Dewpoint is determined annually. Instrument air particulate and oil samples are also taken annually per chemistry department procedures. This frequency is based on the recommendations contained in ISA-RP 7.7 and St. Lucie plant-specific operating experience. The acceptance criteria for instrument air particulate size is three micrometers. The acceptance criteria for oil content is zero w/w or v/v (weight basis or volume basis). The acceptance criteria for dewpoint is 18 °F below the minimum local recorded ambient temperature at the plant site.

By letter dated September 26, 2002, the applicant provided the following response to item 2.

> The applicable instrument air components (compressors, dryers, receivers, etc.) are inspected on a 26 week interval. The Periodic Surveillance and Preventive Maintenance Program does generally follow several, but not all, of the inspection and testing/frequency recommendations in the EPRI NP-7079, "Instrument Air Systems - A Guide for Power Plant Maintenance Personnel." Based on St. Lucie's plant specific operating experience, this preventive maintenance interval is considered acceptable.

The staff finds that the applicant has satisfactorily responded to the staff's concerns as discussed above, and the RAI issues are considered resolved. The staff also finds that the proposed preventive and mitigative actions in their entirety satisfy this program element.

Parameters Monitored or Inspected: The LRA states that the surface conditions of SSCs are monitored through visual examinations and leakage inspections to determine the existence of external and internal corrosion or deterioration. Flood protection features and weatherproofing are visually inspected to verify their material properties. Certain ICW System components are replaced on a given frequency based on operating experience. Diesel generator fuel oil storage tanks are checked for water, and feedwater isolation valve hydraulic accumulators are sampled to detect water in the oil on a periodic basis. The staff finds that the parameters monitored and the inspections performed will effectively manage the aging effects; therefore, the staff finds them acceptable.

Detection of Aging Effects: The LRA states that the aging effects of concern will be detected by visual inspection of surfaces for evidence of corrosion, cracking, leakage, debris, and deterioration, and by monitoring fuel oil and hydraulic oil for contamination. For some equipment, aging effects are managed by periodic replacement in lieu of inspection or refurbishment. The staff finds that techniques used to detect aging effects are consistent with accepted engineering practice and satisfy this program element.

Monitoring and Trending: The LRA states that the inspections, replacements, and sampling activities associated with this program are performed at a specific frequency as listed in administrative procedures, and the results of these activities are documented. The program includes various frequencies depending upon the specific component and aging effects being managed and plant operating experience. Examples of inspections and activities in the Periodic Surveillance and Preventive Maintenance Program include inspection of diesel generator flexible hoses for cracking and inspection for loss of seal of air tight door seals and gaskets for loss of seal. The LRA further states that the frequency of preventive maintenance tasks may be adjusted, as necessary, based on future plant-specific performance and/or industry experience.

Since this is an existing program, in RAI B3.2.11-1, the staff asked the applicant to provide a brief description of how frequently the inspections are conducted and components are replaced. For preventive actions, the LRA states that preventive measures, including charging pump block internal inspection (Unit 2 only), oil sampling and water removal, and replacement of specific structural components and component groups, are based on operating experience. In parameters monitored or inspected, the LRA states that certain ICW system components are replaced at a given frequency based on operating experience. In RAI B3.2.11-1, the staff asked the applicant to identify the specific frequencies of those component inspections and replacements, including how operating experience is used to determine the frequencies.

By letter dated September 26, 2002, the applicant provided the following response.

> The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) currently includes inspection frequencies ranging from 31 days to 10 years depending upon the specific component, the aging effect being managed, and plant-specific operating experience.
>
> Examples of inspections that are part of this program and their current frequencies are provided below:
>
> - Inspection of charging pump blocks (Unit 2 only) for cracking due to fatigue is currently performed on a 6 month frequency.
> - Inspection of diesel fuel oil storage tanks (DOSTs) for accumulated water is performed on a 92 day frequency for Unit 1 and on a 31 day frequency for Unit 2. This is performed by opening drains on the tanks.
> - Oil Sampling of the DOSTs in accordance with ASTM D2276-83 is performed on a 31 day frequency.
>
> Examples of component replacements include intake cooling water pumps and expansion joints, which are scheduled for replacement with new or refurbished equipment on a 96 month and 120 month frequency, respectively.

Operating experience is used to determine preventive maintenance (PM) frequencies. For example, the inspections of charging pump 2A, 2B and 2C blocks are performed as part of the periodic pump valve inspection/overhaul PM activities. Past inspections of blocks during these PM activities have been effective in identifying initiation of cracking in high stress sites. Based upon the service life of the charging pump valves, the frequencies of these PM activities were determined to provide for an early indication of internal fatigue cracking of the blocks.

Water removal and oil sampling of the DOSTs are performed on a frequency as required by the Plant Technical Specifications. Based upon the condition of emergency diesel components as evidenced by past inspections, the frequency of this PM activity is adequate to preclude aging effects associated with loss of material.

The frequencies of overhauls for the ICW pumps and the replacements of discharge expansion joints have been determined based upon the results of past component inspections and consider vendor recommendations. The frequency of the ICW pump overhauls ensures that coating degradations and loss of material due to exposure to the saltwater environment are adequately managed to preclude loss of intended function of the pumps. Likewise, the frequency for replacement of the discharge expansion joints ensures that cracking due to embrittlement is adequately managed.

The frequencies of these tasks may be adjusted as necessary based on future St. Lucie plant-specific performance and/or industry experience. For example, if an enhanced ICW pump coatings product/installation technique demonstrates increased protection of susceptible pump materials, the frequency of periodic overhauls may be increased provided there are no other limiting factors associated with the current frequency.

The staff finds that the applicant has satisfactorily responded to the staff's concerns as discussed above. The issues related to RAI B3.2.11-1 are, therefore, considered resolved. The overall monitoring and trending techniques proposed by the applicant are considered acceptable because inspections, replacements, and sampling activities will effectively manage the applicable aging effects.

Acceptance Criteria: The LRA states that the acceptance criteria and guidelines for the visual inspections are provided in the procedures and preventive maintenance tasks. Acceptance criteria are tailored for each individual inspection considering the aging effect being managed. Examples in the LRA include the following information.

- Inspections for loss of material provide guidance that requires evaluation under the Corrective Action Program if there is evidence of loss of material beyond uniform light surface corrosion.
- Visually detectable cracking requires evaluation under the Corrective Action Program.
- Refurbishments and replacements are performed at a specified frequency based on plant experience or equipment supplier recommendations.

For the staff to make a finding that the acceptance criteria are adequate to manage the aging of SCs that credit this program, the staff performed an inspection of the procedures associated with the Periodic Surveillance and Preventive Maintenance Program. The inspectors determined that the acceptance criteria are adequate to manage the aging of SCs.

Operating Experience: The LRA states that the Periodic Surveillance and Preventive Maintenance Program is an established program at St. Lucie. It utilizes as its bases various industry standards, including regulatory guidelines. The effectiveness and continuous improvement of the Periodic Surveillance and Preventive Maintenance Program are supported by the improved material condition and reliability of the systems and structures that rely on the program, as is documented by internal as well as external assessments during the last several years. The staff finds that the operating experience supports the applicant's conclusion that this program will adequately manage the aging effects of the specified SSCs.

3.0.5.9.3 UFSAR Supplements

The staff reviewed the summary description of the Periodic Surveillance and Preventive Maintenance Program in the UFSAR supplements in Section 18.2.11 of Appendix A1 and Section 18.2.10 of Appendix A2 to the LRA. The staff finds that the information provided in the UFSAR supplements for the aging management of systems and structures discussed above adequately summarizes the program activities, as required by 10 CFR 54.21(d).

3.0.5.9.4 Conclusions

Pending the results of the NRC onsite inspection, the staff finds that the Periodic Surveillance and Preventive Maintenance Program will adequately manage the aging effects so that there is reasonable assurance that the intended functions of the systems and components that credit the program will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and structures discussed above, as required by 10 CFR 54.21(d).

3.0.5.10 Systems and Structures Monitoring Program

The Systems and Structures Monitoring Program is described in Section 3.2.14 of Appendix B to the LRA. This AMP is consistent with the structural aspects of GALL Report AMP XI.S6, "Structures Monitoring Program." However, the applicant's program is plant specific. The Systems and Structures Monitoring Program provides for condition monitoring of components within several plant systems and structures that are within the scope of license renewal. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Systems and Structures Monitoring Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.10.1 Summary of Technical Information in the Application

Section 3.2.14 of Appendix B of the LRA states that the Systems and Structures Monitoring Program provides for condition monitoring of accessible surfaces of SSCs, including welds and bolting. The components comprising the following systems are monitored by this AMP.

- auxiliary feedwater condensate
- chemical and volume control
- component cooling water
- containment cooling
- containment isolation

- containment spray
- diesel generator and support systems
- fire protection
- fuel pool cooling
- instrument air
- intake cooling water
- main feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine
- miscellaneous bulk gas supply
- primary makeup water
- safety injection
- turbine cooling water (Unit 1)
- ventilation
- waste management

In addition, the aging effects for the structural components in the following structures are managed by the Systems and Structures Monitoring Program.

- component cooling water areas
- condensate storage tank enclosures
- containments
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fuel handling buildings
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

The aging effects managed by the Systems and Structures Monitoring Program are (1) loss of material, (2) cracking, (3) fouling (mechanical components only), (4) loss of seal, and (5) change in material properties. The program utilizes inspections to identify aging effects prior to loss of intended function.

3.0.5.10.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.14 of Appendix B of the LRA; the applicant's September 26, 2002, and supplemental November 27, 2002, responses to the staff's RAIs; and the summary description of the Systems and Structures Monitoring Program in Appendix A to the LRA. The staff's evaluation of the Systems and Structures Monitoring Program focused on how the applicant demonstrates that the applicable aging effects of the SCs that credit this program will be managed during the period of extended operation. The staff evaluated the program against the 10 elements that are described in Appendix A of NUREG-1800. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: Section 3.2.14 of Appendix B to the LRA, identifies (1) loss of material, (2) cracking, (3) fouling (mechanical components only), (4) loss of seal, and (5) change in material properties as the aging effects managed by the Systems and Structures Monitoring Program. The Systems and Structures Monitoring Program relies on visual inspection and examination of accessible surfaces of SSCs. The scope of the Systems and Structures Monitoring Program includes inspection of insulated piping and equipment. Inspection of insulated equipment is performed by removal of the insulation to gain appropriate visual access to the equipment. In addition, computer radiography may be used to determine if significant external corrosion is present on insulated equipment. The Systems and Structures Monitoring Program also includes leak inspection of selected ICW system and chemical and volume control system valves, piping, and fittings.

As a result of RAI 3.5-1, several additional concrete components now credit the Systems and Structures Monitoring Program. Specifically, in response to RAI 3.5-1, by letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant committed to monitor change in material properties, cracking, and loss of material for accessible reinforced concrete and masonry block structures. The Systems and Structures Monitoring Program includes a walkdown inspection and aging effects assessment of SCs. With the addition of these structural concrete components, the staff finds that the scope of the Systems and Structures Monitoring Program is acceptable since it includes all the components subject to the aging management effects, which this program is intended to manage.

With the addition of these structural concrete components, the staff finds the scope of the Systems and Structures Monitoring Program to be acceptable since it includes a visual inspection of all the structures and components and an assessment of the aging effects identified for these components by the applicant's aging management review.

Preventive Actions: The applicant identified condition monitoring as the only inspection activity of the Systems and Structures Monitoring Program and states that no preventive actions are taken as a part of this AMP. The staff concurs with this position.

Parameters Monitored and Inspected: Section 3.2.14 of Appendix B to the LRA states that the Systems and Structures Monitoring Program provides a visual inspection of the conditions of structures, system components, piping, and supports to determine the existence of external corrosion, and in some cases, internal corrosion. The application states that steel SCs are monitored for evidence of corrosion, flaking, pitting, gouges, cracking, and other surface irregularities. The monitoring of concrete structural components is consistent with the guidelines provided in American Concrete Institute (ACI) ACI 349.3R-96, "Evaluation of Existing Nuclear Safety Related Concrete Structures," and Structural Engineering Institute/American Society of Civil Engineers (SEI/ASCE) 11-99, "Guideline for Structural Condition Assessment of Existing Buildings." Concrete and masonry components are examined for evidence of exposed rebar, cracking, rust bleeding, spalling, scaling, other surface irregularities, and settlement. In addition, Section 3.2.14 to Appendix B of the LRA states that system commodity and component surface condition are inspected for corrosion, cracking, fouling, other surface irregularities, and leakage for selected systems.

For inaccessible components, the applicant intends to inspect accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components. For inaccessible concrete structural components, the applicant intends to enhance its Systems and Structures Monitoring Program for license renewal activities by providing additional guidance for inspections during the period of extended operation. In RAI B.3.2.14-2, the staff requested further information regarding these planned enhancements for inspecting inaccessible concrete. The applicant responded by letter dated September 26, 2002, stating that concrete surfaces below ground water require specifically tailored inspection criteria. In particular, the applicant stated that some interior portions of the reactor auxiliary building (RAB) are below ground water and accessible for inspection. The applicant intends to inspect these interior portions of the RAB and use their material condition as an indicator for other below-grade inaccessible concrete components. In addition, the applicant stated that examination of representative samples of below-grade concrete, when excavated for any reason, will be included as part of the Systems and Structures Monitoring Program.

The staff concurs with the applicant's approach to inspecting normally inaccessible SCs as indicated above. The use of accessible components and similar material and environment as indicators for aging of inaccessible components is an approach that has been used by previous applicants and has been accepted by the staff. For accessible components, the staff finds that the parameters monitored by the Systems and Structures Monitoring Program, such as cracking and corrosion of external surfaces, are acceptable because they are directly related to the degradation of SCs, and visual inspections are effective and adequate to detect such conditions.

Detection of Aging Effects: Section 3.2.14 to Appendix B of the LRA states that the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties are detected by visual inspection of surfaces for evidence of degradation or leakage.

Several components in the ICW system credit the Systems and Structures Monitoring Program for managing loss of material in the raw water environment. In RAI B.2.10-2, the staff asked the applicant to provide the applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the ICW system including cast-iron, carbon steel, bronze, Monel, and stainless steel valves, piping, tubing, and fittings; stainless steel orifices; and stainless steel thermowells exposed internally to the raw water environment. In its response dated September 26, 2002, the applicant provided the following information.

> As described in LRA Appendix B, Section 3.2.14 (page B-58,) the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping and fittings at selected locations of Intake Cooling Water (ICW) by leakage inspection to detect the presence of internal corrosion. Loss of material for orifices, thermowells, and tubing/fittings due to internal exposure to raw water is also managed by leakage inspection via the Systems and Structures Monitoring Program as listed in LRA Table 3.3-9 (pages 3.3-60 and 3.3-61). Leakage inspection of ICW orifices, thermowells, and tubing/fittings was inadvertently omitted from the Systems and Structures Monitoring Program description in LRA Appendix B. These locations mostly encompass small bore piping components not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4" instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the Component Cooling Water heat exchangers below

design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:

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

- For small valves, piping/tubing/fittings, thermowells, and orifices leakage does not affect the system function because the small size of these components limits the leakage. The St. Lucie plant-specific operating experience for these components demonstrates that leakage for this equipment has not been significant.

The leakage inspection is currently performed at least once per 18 months. This frequency is based on St. Lucie plant-specific operating experience. The frequency of inspections may be adjusted as necessary based on future inspection results and industry experience.

The staff found that the applicant's response, as discussed above, did not adequately address the aging management of the small valves, piping/tubing/fittings, thermowells, and orifices. Further information was provided by letter dated November 27, 2002, describing the materials, operating history, and repair history of the small piping and components in the intake cooling water system, but the applicant continued to rely on leakage detection for aging management. The staff created Open Item 3.0.5.10-1 to cover the use of leakage detection because leakage frequently indicates a loss of component intended function.

By letter dated March 28, 2003, the applicant provided additional information related to the use of leakage detection in the Systems and Structures Monitoring Program. For the ICW system, the Systems and Structures Monitoring Program is used in conjunction with the Intake Cooling Water Program. The applicant's March 28, 2003, submittal provides the following information related to the ICW system.

As described in LRA Appendix B, Subsection 3.2, the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping, and fittings at selected locations of ICW by leakage inspection to detect the presence of internal corrosion. These locations mostly encompass small bore piping components, not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4 inch instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the Component Cooling Water heat exchangers below CLB design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:

a. Maintenance history shows that localized failures of cement lining or internal epoxy coating of intake cooling water lines result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage which provides adequate time for repairs before the system function or structural integrity of the line is degraded.

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

In addition to the above process, periodic crawl-through inspections of the large bore piping, as described in the Intake Cooling Water Inspection Program, are conducted to identify, evaluate and repair any component degradation. Although no crawl-through inspections can be performed on the small-bore piping, the mechanical joints (i.e., flanged connections) between the small bore and large-bore piping are inspected as part of the crawl-through inspections of the large bore piping. These mechanical joints are representative of other mechanical joints in the small-bore lines and are the most likely locations for corrosion as discussed above. Therefore, the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of Intake Cooling Water.

For the chemical and volume control system, leakage detection is used for portions of the system that were previously heat traced and are therefore subjected to stress-corrosion cracking (SCC). The applicant's March 28, 2003, letter provided the following information related to the chemical and volume control system.

As described in LRA Appendix B Subsection 3.2.14, "Systems and Structures Monitoring Program," leakage inspections are credited for managing external cracking of selected CVCS valves, piping, and fittings. These leakage inspections only apply to the previously heat traced portions of CVCS (i.e., boric acid make-up lines). A review of St. Lucie plant-specific operating experience for CVCS identified that external stress corrosion cracking (SCC) has occurred in the previously insulated heat traced lines. The SCC was attributed to contaminated insulation due to the water used to wash down external surfaces of piping components. The combination of high halogens (e.g., chlorides) and high temperature (i.e., approximately 180°F) due to heat tracing increased the susceptibility of the lines to SCC. Corrective actions to address this condition included inspection of all susceptible boric acid makeup piping (including liquid penetrant examinations of high chloride concentration areas), replacement of defective portions, and administrative enhancements for cleaning external surfaces of stainless steel piping. Additionally, as part of a boric acid concentration reduction project, CVCS piping insulation has been removed since heat tracing is no longer required. The results of SCC are localized minor leakage (not catastrophic failure of the piping) detectable by periodic visual inspection under the Systems and Structures Monitoring Program. Since the initial identification of SCC and corrective actions taken in 1990, there have only been two occurrences of minor leakage due to external SCC in the previously heat traced lines. One leak occurred in Unit 1 in 1996, and one on Unit 2 in 1998.

For the ICW system, operating experience has demonstrated that the leakage results from small corrosion cells where localized failures of the coatings occur. The small amount of leakage will not impact the system function, the operating experience has demonstrated that the structural integrity of the system is maintained, and corrective actions have led to replacement of approximately 75 percent of the small bore piping with corrosion-resistant materials. For the chemical and volume control system, the applicant has removed the source of the aggressive environment, performed inspections, and replaced piping as necessary. Operating experience has indicated only two instances (one on each unit) of minor leakage. Based on the above, the staff concludes that the Systems and Structures Monitoring Program is adequate to detect aging in the ICW and chemical and volume control systems, and therefore, Open Item 3.0.5.10-1 is considered closed.

Monitoring and Trending: Section 3.2.14 of Appendix B to the LRA states that the frequency of inspections varies depending on the SSC being inspected. The application states that the documented results of the visual inspections are used together with industry experience to determine if the frequency of scheduled inspections should be adjusted.

In RAI B.3.2.14-1, the staff requested that the applicant provide more detail regarding the inspection intervals and sample sizes for the SSCs that credit the Systems and Structures Monitoring Program. By letter dated September 26, 2002, the applicant stated that inspections carried out by the Systems and Structures Monitoring Program will be initially performed at a frequency of 5 years. However, leakage inspection of the intake cooling water will be performed at an 18-month frequency. In general, the frequency of inspections may be adjusted as necessary based on future inspection results and industry experience. The applicant further stated that sampling will not be used for the Systems and Structures Monitoring Program; however, sampling may be implemented in the future if the inspection results warrant this approach.

The staff finds an inspection schedule of at least once every 5 years to be sufficient for the aging management of components that credit the Systems and Structures Monitoring Program. Also, the applicant's commitment to adjust the inspection frequency based on inspection results and industry experience is acceptable to the staff.

Acceptance Criteria: The applicant identified general acceptance criteria in its description of the Systems and Structures Monitoring Program in the LRA. Specifically, Section 3.2.14 of Appendix B to the LRA states that detailed structural and system or component material condition inspections are performed in accordance with approved plant procedures. Existing procedures include detailed guidance for inspecting and evaluating the material condition of SSCs within the scope of this program. The guidance includes specific parameters to be monitored and criteria to be used for evaluating identified degradation.

For the staff to make a finding that the above acceptance criteria are adequate to detect the aging of component groups that credit this program, the staff inspected the procedures associated with the Systems and Structures Monitoring Program. In particular, the staff reviewed the forms used to document the assessment of the material condition of components, as well as the system checklists used for documenting relevant information from system walkdowns. The staff inspection also reviewed the procedures associated with the Systems and Structures Monitoring Program to determine the level of detail, the specific parameters to be monitored for each component type, and the criteria used to evaluate an identified degradation.

The NRC staff inspection team found the procedures associated with the Systems and Structures Monitoring Program to be acceptable in terms of their detail and completeness. Inspection checklists for reinforced concrete, masonry, structural steel, and roofing materials were among those examined by the inspection team and found to be adequate. In addition, the inspection team reviewed the applicant's condition reports, which provide a process by which any conditions of concern may be identified, tracked, evaluated, and corrected. As a result of the review, the inspection team concluded that the plant procedures for the Systems and Structures Monitoring Program, with their associated acceptance criteria, contain detailed guidance that includes specific parameters and criteria for evaluating an identified degradation. The staff concludes that the acceptance criteria for the Systems and Structures Monitoring Program provide reasonable assurance that observed degradation of the structural components managed by this program will be adequately evaluated so that these structural components will continue to perform their intended functions during the period of extended operation as required by 10 CFR 54.21(a)(3).

Operating Experience: In Section 3.2.14 to Appendix B of the LRA, the applicant stated that the Systems and Structures Monitoring Program has been an ongoing program at St. Lucie and has been enhanced over the years to include the best practices recommended by industry guidance. Inspection findings, such as degraded conditions, are documented in accordance with the plant's Corrective Action Program in order to prevent recurrence by either plant modifications or program enhancements.

In RAI B.3.2.14-3, the staff requested that the applicant provide specific examples of enhancements and improvements that have been made to the Systems and Structures Monitoring Program as a result of previous inspection findings. By letter dated September 26, 2002, the applicant stated that examples of program enhancements due to observed degradation include increased inspections of the intake structure concrete, as well as increased frequency of inspections of steel components that have been more susceptible to corrosion. The staff finds the above enhancements to the Systems and Structures Monitoring Program to be acceptable examples of the type of program enhancements that are necessary to ensure that the aging of components that credit the Systems and Structures Monitoring Program are adequately managed.

In RAI B.3.2.14-2, the staff requested that the applicant provide further details regarding past inspections of inaccessible concrete structural components which may be subjected to aggressive chemical attack due to the chemistry (pH, sulfides, chlorides) of ground water. By letter dated September 26, 2002, the applicant stated the following.

> Inaccessible concrete has been inspected during past excavation activities and no concrete degradation was noted. Specifically, a portion of the below grade Containment Shield Building was exposed during the Unit 1 Steam Generator Replacement Project in 1997. Also, portions of the Unit 1 Cask Crane foundations and the Unit 1 Component Cooling Water structure below grade concrete were exposed during exploratory excavations associated with the Unit 1 Cask Crane replacement in 2002.

The applicant's response that no degradation of below-grade concrete has been observed is acceptable to the staff. The applicant has committed to enhance the Systems and Structures Monitoring Program by developing "specifically tailored inspection criteria" to manage the aging of inaccessible concrete components. A description of this enhancement is provided above under the parameters monitored or inspected subsection.

In conclusion, the staff finds that the applicant's operating experience has demonstrated that the Systems and Structures Monitoring Program has effectively maintained the integrity of the SSCs that currently credit this program, and that the effects of aging will be adequately managed so that there is reasonable assurance that the SCs intended functions will be maintained during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.5.10.3 UFSAR Supplement

The staff reviewed the summary description of the Systems and Structures Monitoring Program in the UFSAR supplement in Section 18.2.14 of Appendix A1 and Section 18.2.13 of Appendix A2 to the LRA. The staff finds that the information provided in the UFSAR supplements for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.0.5.10.4 Conclusion

The staff concludes that the applicant has demonstrated that the aging effects associated with the Systems and Structures Monitoring Program will be adequately managed so that there is reasonable assurance that the intended functions of the SCs will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements in Appendix A to the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the SCs discussed above, as required by 10 CFR 54.21(d).

3.1 Aging Management of Reactor Coolant System

In Section 3.1 of the LRA, the applicant identifies the following RCS mechanical components subject to an AMR.

- reactor coolant piping
- pressurizers
- reactor vessels (includes pressure boundary of control element drive mechanisms)
- reactor vessel internals
- reactor coolant pumps
- steam generators

The applicant described the results from the AMR for the Class 1 portions of the RCS, including the RVs, reactor vessel internals, (RVIs) pressurizers, SGs, and Class 1 piping, valves, and pumps in Section 3, "Reactor Coolant Systems," of the LRA. In Table 3.1-1, "Reactor Coolant Systems," of the LRA, the applicant summarizes the results from the AMR for these RCS components. The applicant describes the applicable AMPs for these components in Appendix B to the LRA, "Aging Management Programs." This section of the SER includes the staff's review of the AMR results presented in Section 3.1 of the LRA and includes the mechanical components for the RCS subsystems identified above.

3.1.0 System-Specific Aging Management Programs

3.1.0.1 Alloy 600 Inspection Program

3.1.0.1.1 Summary of Technical Information in the Application

The applicant states that the objective of the Alloy 600 Inspection Program is to manage the aging effect of cracking due to primary water stress-corrosion cracking (PWSCC) by utilizing walkdown inspections, which include visual inspections of the RVH external surfaces and other susceptible leakage locations in the RCS. The program also includes those RVH inspections the applicant committed to in its response to NRC GL 97-01 and NRC Bulletin 2001-01. The scope and schedule of future RVH penetration inspection requirements are pending the issuance of industry guidance.

The applicant states that the scope of the Alloy 600 Inspection Program encompasses the Alloy 600 RCS pressure boundary components, including RVH penetration nozzles, reactor head vent pipes, pressurizer instrument nozzles and heater sleeves, piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray pipe fittings, piping dissimilar metal welds, and Unit 2 control element drive mechanism motor housing lower end fittings.

3.1.0.1.2 Staff Evaluation

The applicant describes the Alloy 600 Inspection Program and its program attributes in Section B.3.2.1 of Appendix B to the LRA.

The staff's original basis for inspecting Alloy 600 RVH penetration nozzles in U.S. PWRs is provided in GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Head Penetrations", issued on April 1, 1997. Between November 2000 and April 2001, subsequent to the issuance of GL 97-01, RCPB leakage was identified from the RVH penetration nozzles of four U.S. PWR-design light water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These cracks initiated from the outer surface of the nozzle, either in the associated J-groove weld or heat-affected-zone, and not from the inside surface of the nozzle, as was assumed in the industry responses to NRC GL 97-01. These cracks penetrated through the nozzles and were initially identified as circumferential cracking in U.S. RVH penetration nozzles. In NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles", issued on August 3, 2001, the staff discussed the generic safety significance and impacts of these cracks on RVH penetration nozzles and recommended that enhanced visual examination or volumetric examination methods be used for the inspection of RVH penetration nozzles.

In March 2002, during a refueling outage at the Davis-Besse Nuclear Power Station, the licensee for the plant reported the occurrence of reactor coolant leakage from RVH penetration nozzles. As a result of follow-up evaluations of the reactor coolant leakage, the licensee reported that, the leakage resulted in significant boric-acid-related wastage of the RVH. The wastage affected the entire thickness of the RVH with the exception of the RVH cladding. On March 18, 2002, the NRC issued NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," to owners of PWR designs, requesting that the licensees address the impact of the Davis-Besse event on the structural integrity of their RVHs and associated penetration nozzles. On August 9, 2002, the staff issued NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," to address additional technical issues resulting from the Davis-Besse event. In NRC Bulletin 2002-02, the staff specifically suggested that further augmented inspections, more comprehensive than those suggested in NRC Bulletin 2001-01, be performed on RVH penetration nozzles.

During V.C. Summer refueling outage 12 (October 2000), a through-wall crack was identified in the RV hot-leg nozzle safe-end weld. This weld was fabricated from Alloy 82/182 weld material. NRC IN 2000-17 and 2000-17, Supplement 1, dated October 18, 2000, and November 16, 2000, respectively, provide details of the V.C. RV hot-leg nozzle weld cracking event. However, the staff is currently addressing the generic implications of the V.C. Summer hot-leg nozzle safe-end weld cracking event with the U.S. nuclear industry owners groups, research organizations, and licensees to determine which inspection methods will be necessary for Class 1 safe-end welds fabricated from Alloy 82/182. The staff will resolve the implications of the event, as it relates to the structural integrity of the St. Lucie RV hot-leg nozzle safe-end welds, within the current licensing periods for units 1 and 2. Therefore, pursuant to 10 CFR 54.30, the staff considers this issue to be outside the scope of license renewal.

The aging of RVH penetration nozzles and other Class 1 components made from nickel-based alloys due to PWSCC is an emerging issue that is currently being evaluated and resolved by the NRC and the industry. The staff assessed whether the applicant's AMP accounted for the implication of the Davis-Besse event and other applicable operating experience (i.e. V.C Summer, etc). The staff assessed the program against 10 elements that are described in Appendix A to NUREG-1800.

The staff assessed the corrective actions, confirmation process, and administrative controls program attributes for the Alloy 600 Inspection Program as part of the staff's assessment of the applicant's Quality Assurance Program, which is evaluated in Section 3.0.4 of this SER.

Program Scope: The applicant stated that the Alloy 600 Inspection Program is a plant-specific program that is designed to detect PWSCC in the Alloy 600 components that serve a pressure boundary function. The scope of the Alloy 600 Inspection Program includes the Alloy 600 Class 1 RCS components listed in Section 3.1.1.1 of this SER, as well as FPL's responses to NRC GL 97-01 and NRC Bulletin 2001-01. Aging effects in the Alloy 600 steam generator tubes are monitored by the applicant's Steam Generator (SG) Integrity Program.

The Program Scope submitted in the application did not include NRC Bulletins 2002-01 or 2002-02 as part of the CLB for the Alloy 600 Inspection Program. Therefore, in RAI B.3.2.1-1, the staff requested the following actions of the applicant:

- Update your [Scoping] program attribute to include your response to NRC Bulletin 2002-01 (dated April 2, 2002, in FPL letter L-2002-061).

- Either summarize the scope and results of inservice and additional augmented (if applicable) examinations that have been performed on the St. Lucie Units 1 and 2 RVHs to date and comment on the impact the inspection results will have on the program attributes for the A600IP, or if your responses to NRC Generic Letter 97-01 and NRC Bulletin 2001-01 provide this type of information, reference your responses to these generic communications.

In its response to RAI B.3.2.1-1, dated September 26, 2002, the applicant stated that it will continue to be a participant in the industry programs for assessing and managing PWSCC in Alloy 600 RVH penetration nozzles. The applicant emphasized that the work performed by the EPRI Materials Reliability Program and the Nuclear Energy Institute (NEI) in assessment of this issue is an integral part of the Alloy 600 Inspection Program and that the applicant's commitments made in response to NRC requests regarding this issue are considered to be part of the program. The applicant also clarified that the scope of the Alloy 600 Inspection Program includes the applicant's responses to NRC Bulletin 2002-01 (FPL Letters L-2002-061 and L-2002-116 dated April 2, 2002, and June 27, 2002, respectively), and commitments made to NRC Bulletin 2002-02 (FPL letter L-2002-185 dated September 11, 2002). The response to

RAI B.3.2.1-1 updates the Program Scope program attribute for the Alloy 600 Inspection Program to the most current CLB for the RVH penetration nozzles and is therefore acceptable.

In Table 3.1.3-1 of the LRA, the applicant did not list the Alloy 600 Inspection Program as an applicable program for managing cracking in Alloy 600 RCS flow baffles, core stabilizing lugs, and core stop lugs. Instead, the applicant identified that it will use the Chemistry Control Programs and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in these components. Table 3.1.3-1 indicates that the RCS flow baffles serve a flow distribution function, and the core stabilizing lugs and core stop lugs serve a core support function. Neither of these components serves a pressure boundary function for the RCS; therefore, they are not within the scope of the Alloy 600 Inspection Program. This is acceptable to the staff.

Preventive Actions: The Alloy 600 Inspection Program includes the following actions for mitigating or preventing the initiation of PWSCC.

- nickel plating of the surfaces of Alloy 600 components that are exposed to treated water
- replacement of leaking Alloy 600 instrument nozzles with Alloy 690 material
- preventive replacement of selected pressurizer and RCS piping instrument nozzles with Alloy 690 material

Pure nickel (i.e., nickel in its elemental form) is highly resistant to corrosive mechanisms, including general corrosion and SCC. The applicant considers an electrochemical potential of -200 million electron volts (MeV) to be the threshold for initiation and growth of SCC in Alloy 600 materials. The staff concurs with this value as the threshold for initiation and growth of SCC in Alloy 600 materials under PWR primary water environments. At electrochemical potentials less than -200 MeV, the staff considers that the potential for initiating and growing SCC in Alloy 600 is inhibited. Plating of nickel onto the surfaces of Alloy 600 materials protects the material from the reactor coolant and lowers the electrochemical potential of the component below this level. The staff considers that Alloy 690 has improved resistance to SCC in comparison to Alloy 600. Replacing the instrument nozzles with nozzles fabricated of Alloy 690 should improve the resistance of the nozzles to stress corrosion. The staff concurs that these practices are acceptable mitigative practices and therefore concludes that the preventive action is acceptable.

Parameters Monitored or Inspected: The applicant states that the program monitors the effect of PWSCC on the intended function of the affected components by detection of cracks and identification of reactor coolant leakage. In Appendix C, Section 5.1 to the LRA, the applicant states that pitting is normally an issue only when the dissolved halide and oxygen concentrations in a coolant are in excess of 100 parts per billion (ppb) or the dissolved sulfate concentrations are in excess of 150 ppb. The applicant implements the Water Chemistry Program, as discussed in Section B.3.2.5.1 of the LRA, to ensure that the concentrations of these impurities for the RCS coolant are not in excess of these concentrations. The applicant therefore provides an acceptable basis in LRA Appendix C, Section 5.1 for concluding that pitting and crevice corrosion are not applicable effects for Alloy 600 components within the scope of the Alloy 600 Inspection Program.

The aging effects monitored by the Alloy 600 Inspection Program are consistent with those evaluated and accepted by the staff in Sections 3.1.1.1.2, 3.1.2.2.2, and 3.1.3.2 of this SER. The aging effect monitored by the A600IP (i.e., cracking) is therefore acceptable to the staff. The Steam Generator (SG) Integrity Program is credited with managing cracking and loss of material in the Alloy 600 SG tubes. The staff evaluates the Steam Generator Integrity Program in Section 3.1.6.2.2 of this SER. The staff assesses the Water Chemistry Program in Section 3.0.3 of this SER.

Detection of Aging Effects and Monitoring and Trending: The applicant stated that visual inspections of 100 percent of the Unit 1 and 2 RVHs will be conducted in accordance with the applicant's commitments to NRC Bulletins 2001-01 and 2002-02. The applicant indicated that the results of the inspections will be utilized to determine the need for additional bare metal visual or volumetric examinations.

The applicant also stated that leak tests and walkdowns are used for detecting through-wall PWSCC of Alloy 600 components. The leak tests consist of visual inspections of each susceptible location in accordance with the requirements of the existing Boric Acid Wastage Surveillance Program. Leakage is detected by steam discharge, borated water, or other evidence of fluid escape. This is consistent with the applicant's commitments to NRC Bulletins 2001-01 and 2002-01.

The applicant stated that, in response to NRC Bulletin 2001-01, the industry will develop a follow-up examination plan for RVH penetrations. The schedule and frequency for follow-up examinations will be determined based on the results of the initial examinations and the issuance of industry guidance to be provided by the EPRI Materials Reliability Program and NEI. The visual inspections of the RVH and other RCS Alloy 600 components are performed in accordance with the Boric Acid Wastage Surveillance Program.

The applicant also stated that the comprehensive list of monitoring and trending activities discussed in the GALL Report for monitoring and trending PWSCC in Alloy 600 primary pressure boundary components include program activities that are contained in several separate AMPs. The staff determined that the monitoring and trending attributes for the Alloy 600 Inspection Program, when taken in context with the monitoring and trending attributes for the Chemistry Control, Boric Acid Wastage Surveillance, and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Programs, are acceptable.

In its response to RAI B 3.2.1-1, the applicant clarified that commitments made by the applicant in response to NRC Bulletin 2002-02 and future inspection results could have an impact on the program and that the specific program attributes would be adjusted at that time. The applicant indicated that the Unit 1 and 2 UFSAR supplements for the Alloy 600 Inspection Program, provided in Appendix A1, Subsection 18.2.1, for Unit 1 and Appendix A2, Subsection 18.2.1, for Unit 2, will be revised to incorporate FPL commitments in response to the NRC communications referenced in previous paragraphs.

To address the implications of the Oconee and Davis-Besse operating experience on the St. Lucie Alloy 600 Inspection Program, the staff requested in Open Item 3.1.0.1-1 that the applicant provide a commitment to implement any inspection methods, inspection frequencies, and acceptance criteria that are recommended by industry organizations as a result of their initiatives on Inconel components and materials (e.g., as recommended by the Combustion

Engineering Owners' Group (CEOG), NEI, or the EPRI Materials Reliability Program Integrated Task Group on Inconel Materials and found acceptable by the NRC), as well as any further requirements that may result from the staff's resolution of the issue of PWSCC in nickel-based alloy components.

The applicant submitted its response to Open item 3.1.0.1-1 in FPL Letter L-2003-070, dated March 28, 2003. In its response, the applicant stated that FPL will implement the commitments made in response to NRC Bulletins 2001-01, 2002-01, and 2002-02, and any commitments made in response to future communications associated with PWSCC of nickel-based alloy components. In addition, the applicant clarified that the evaluation of work performed under the EPRI Materials Reliability Program and NEI is an integral part of the Alloy 600 Inspection Program.

On February 11, 2003, the staff issued generic NRC Order EA-03-009 to holders of operating licenses for domestic PWR-designed light water reactor facilities. Order EA-03-009 contains augmented volumetric, surface, and bare surface visual inspection requirements for the RVH and associated penetration nozzles of U.S. PWRs. The Order requires addressees to implement the augmented inspection requirements on an interim basis until such time that the augmented inspection requirements can be incorporated into a revision of 10 CFR 50.55a or codified in an edition of the ASME Boiler and Pressure Vessel Code, Section XI, endorsed by reference in 10 CFR 50.55a. The augmented requirements of Order EA-03-009 may be accessed through the NRC's current public Web site on the World-Wide-Web.[1]

The table attached to NRC Order EA-03-009 confirms that the augmented inspection requirements in Order EA-03-009 are applicable to the RVHs and the associated penetration nozzles (including their associated Alloy 82/182 structural welds) at St. Lucie Units 1 and 2. The requirements in Order EA-03-009 augment any prior inspection programs for the St. Lucie RVHs and associated penetration nozzles that may have been committed to by the applicant in response to NRC Bulletin 2002-02. Implementation of the commitment made in response to Open Item 3.1.0.1-1 will be in compliance with the order and will address the structural integrity of the RVHs and associated penetrations nozzles (including associated Alloy 82/182 structural welds) through the extended period of operations. The staff, therefore, concludes that the applicant's response to Open Item 3.1.0.1-1 is acceptable and considers Open Item 3.1.0.1-1 to be resolved.

NRC Bulletins 2001-01, 2002-01, and 2002-02 are only relevant to the assessment of PWSCC-induced, through-wall cracking that has occurred in the partial penetration J-groove welds of upper RVH penetration nozzles. These bulletins do not pertain to the evaluation of PWSCC-induced cracking that could potentially occur in other nickel-based alloy locations within the RCPB. Therefore, in Open Item 3.1.0.1-2, the staff requested that the applicant provide further discussion and clarification of the inspection methods that will be used for the nickel-based alloy components in the remaining RCS Class 1 subsystems (such as those in the St. Lucie pressurizers, SGs, hot legs, and RVIs). The applicant submitted the following response to Open Item 3.1.0.1-2 in FPL Letter L-2003-070, dated March 28, 2003.

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1 NRC Order EA-03-009 may be accessed at the following web address on the World-Wide-Web:

http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation/vessel-head-degradation-files/order-rpv-inspections.pdf

As discussed in the St. Lucie License Renewal Application (LRA) Appendix A1 Section 18.2.1, Appendix A2 Section 18.2.1, Appendix B, Subsection 3.2.1, the St. Lucie Alloy 600 Inspection Program includes reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, Reactor Coolant System (RCS) piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings, and RCS dissimilar metal welds. For aging management of the Alloy 600 components and welds, the Alloy 600 Inspection Program is performed in conjunction with visual and other examinations performed in accordance with the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program.

The applicant's response to Open Item 3.1.0.1-2 clarifies which nickel-based alloy locations are within the scope of the Alloy 600 Inspection Program. The response also indicates that the Alloy 600 Inspection Program uses VT-2 visual inspection methods, as required by ASME Section XI, Table IWB-2500-1, Inspection Category B-P, as the basis for inspecting ASME Class 1 nickel-based alloy components that are located in the RCPB. The applicant's inspections for the upper RVHs and the penetration nozzles are based on the augmented inspection requirements of NRC Executive Order EA-03-009.

In its reply to Open Item 3.1.0.1-1; the applicant stated that it will revise the Alloy 600 Inspection Program in response to any future NRC communications associated with PWSCC in nickel-based alloy components. The applicant also stated that it would evaluate the work performed by industry groups for inclusion in the Alloy 600 Inspection program. The staff concludes that the applicant's response to Open item 3.1.0.1.2-2 is acceptable, since the Alloy 600 inspection Program will be periodically revised and is applicable to the nickel-based alloy components in the reactor coolant system. The staff therefore considers Open Item 3.1.0.1-2 to be closed.

Acceptance Criteria: The applicant states that the acceptance criteria for identified flaws will be developed using approved fracture mechanics methods and industry-specific or plant-specific data. Evaluations would consider the stresses at the flaw location and industry-developed crack propagation rates, before implementing any corrective action.
The applicant does not define the acceptance criteria for partial through-wall flaws identified and sized by volumetric inspection methods, or those identified by surface examination methods and sized by volumetric examination methods. As a minimum, the applicant is required by 10 CFR 50.55a to comply with the flaw acceptance criteria specified for ASME Class 1 components in the ASME Code, Section XI, Articles IWA-3000 and IWB-3000, regardless of whether the material is fabricated from Alloy 600.

The staff is aware that the PWR industry organizations, such as NEI and EPRI's Integrated Task Group on Alloy 600, are in the process of performing detailed industry studies on cracking of Alloy 600 base metal components and Alloy 82/182 weld metal components. For the Class 1 Alloy 600 components within the scope of the applicant's Alloy 600 Inspection Program, the results of these industry initiatives may include recommendations for implementing alternative acceptance criteria to those required by Section XI of the ASME Code. The applicant's acceptance criteria program attribute for the Alloy 600 Inspection Program implies that the applicant will be use alternative acceptance criteria for partial through-wall flaws that are detected in the Class 1 Alloy 600 components. The applicant may use alternative acceptance criteria developed either by the applicant or the industry for partial through-wall flaws if the alternative criteria have been submitted to and accepted by the staff pursuant to 10 CFR 50.55a(a)(3).

The applicant's acceptance criterion for the visual inspections (i.e., for through-wall flaws resulting in leakage of the primary coolant) is no pressure boundary leakage. This acceptance criterion for performing visual inspections of the Class 1 Alloy 600 RCS components is acceptable to the staff because it complies with the "no RCS pressure boundary leakage" requirement specified in the St. Lucie Technical Specifications.

Operating Experience: The applicant states that it has been an active participant in the CEOG, EPRI, and NEI initiatives regarding cracking of Alloy 600 RCS components. The applicant further states that the Alloy 600 Inspection Program was created in response to NRC GL 97-01 and updated in response to NRC Bulletin 2001-01. The applicant states that it has proven experience in addressing the concerns of the generic letter and the bulletin and that, to date, it has performed visual inspections on the top of RVHs for leakage as part of the Boric Acid Wastage Surveillance Program. No evidence of leakage from the Alloy 600 RVH penetrations has been identified. However, in the response to RAI 3.2.1-1, the applicant also indicated that the scope and results of inservice inspection (ISI) examinations and augmented examinations performed to date on the RVHs are summarized in its responses to NRC Bulletins 2002-01 and 2002-02, and that the results of the visual examinations performed to-date do not have an impact on the program attributes for the Alloy 600 Inspection Program.

PWSCC has been reported in Alloy 82/182 J-groove welds that are used to join Alloy 600 small bore nozzles to CE-designed pressurizers, SGs, and/or hot legs.[2] The applicant confirmed that visual inspections performed at St. Lucie Units 1 and 2 have identified leakage of Alloy 600 pressurizer and Class 1 piping instrument nozzles. In all cases, the leaking nozzles have been removed and replaced in accordance with the requirements of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The applicant indicated that the visual inspections provided timely detection and repair of RCS pressure boundary leakage. The applicant's TLAA associated with these repairs (half-nozzle repair methods) addresses management of this degradation and is discussed in Section 4.6.4 of the LRA. The staff evaluates the TLAA in Section 4.6.4 of this SER.

3.1.0.1.3 UFSAR Supplement

The applicant's UFSAR Supplement summary descriptions for the Alloy 600 Inspection Program are provided in Section 18.2.1 of Appendix A1 to the LRA for Unit 1 and Section A2 of the LRA for Unit 2. These UFSAR supplement summary descriptions provide an overview of the program as described in Section B.3.2.1 of Appendix B to the application.

In its March 28, 2003, response to Confirmatory Item 3.1.0.1-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions for the Alloy 600 Inspection Program, as given in Section 18.2.1 of Appendix A1 to the LRA and in Section 18.2.1 of Appendix A2 to the LRA, to incorporate the following statement:

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2 These occurrences have been reported as part of relief requests for implementing mechanical nozzle seal assembly repairs or half-nozzle replacements for leaking Alloy 600 nozzles of CE-designed pressurizers, SGs, or hot-leg piping, or through docketed correspondence to the NRC Document Control Desk. Licensees that have reported leakage in Alloy 600 nozzle locations of CE-designed facilities have included Southern California Edison (the licensee for San Onofre), Entergy Operations, Inc. (the licensee for Waterford and ANO-2), Omaha Public Power District (the applicant for FCS), Arizona Public Service (the licensee for Palo Verde), and Florida Power and Light (the licensee for St. Lucie).

> The Alloy 600 Inspection Program will implement FPL commitments in response to NRC communications associated with primary water stress corrosion cracking (PWSCC) of Inconel materials (including Alloy 600 and Alloy 182/82 materials). In addition, this program will be maintained consistent with the recommendations of the Combustion Engineering Owners Group (CEOG), Nuclear Energy Institute (NEI), and Electric Power Research Institute (EPRI) Material Reliability Program (MRP).

The staff has confirmed that the latest versions of the UFSAR Supplement summary descriptions for the Alloy 600 Inspection Program have incorporated the revision proposed by the applicant. Therefore, the staff considers Confirmatory Item 3.0.5.1-1 closed and concludes that the UFSAR Supplement summary descriptions for the Alloy 600 Inspection Program, as given in Section 18.2.1 of Appendix A1 to the LRA and in Section 18.2.1 of Appendix A2 to the LRA, are acceptable.

3.1.0.1.4 Conclusions

The staff has reviewed the information provided in Section B.3.2.1 of Appendix B to the LRA, Section 18.2.1 of LRA Appendices A1 and A2, and Item 9 of Tables 1 and 2 of SER Appendix D, as supplemented by the applicant's responses to RAI B.3.2.1-1, Open Items 3.1.0.1-1 and 3.1.0.1-2, and Confirmatory Item 3.1.0.1-1. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging associated with Alloy 600 Class 1 components will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.2 Thermal Aging Embrittlement of CASS Program

3.1.0.2.1 Summary of Technical Information in the Application

In Section 3.1.6. of Appendix B to the LRA, the applicant identifies that aging management of RCS components made from cast austenitic stainless steels (CASS) will be managed by the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (henceforth identified as the CASS Program).

The applicant states that the CASS Program is designed to identify those CASS components that are susceptible to thermal aging embrittlement and to monitor these components for the effects of thermal aging embrittlement on the fracture toughness properties. For those CASS components that the program identifies as being potentially susceptible to thermal aging, the program specifies either enhanced implementation of volumetric examinations for the detection and sizing of cracks in the components, or implementation of plant-specific or component-specific flaw tolerance evaluations for the CASS materials.

The applicant states that the CASS Program is consistent with the 10 program attributes of AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," as specified in the GALL Report. The applicant also states that commitment dates associated with implementation of this AMP are contained in Appendix A of the LRA.

3.1.0.2.2 Staff Evaluation

The 10 program attributes in GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage thermal aging, and hence loss of fracture toughness properties, in RCS components made from CASS. The program attributes for GALL AMP XI.M12 are in accordance with the staff's position on evaluation of CASS materials, as given in the ISG on CASS dated May 19, 2000. In Section 3.1.6 of Appendix B to the LRA, the applicant states that the program attributes for the CASS Program are consistent with those specified in AMP XI.M12 of the GALL Report. The applicant retains the program description of the CASS Program, as well as the descriptions of the program's 10 attributes, on record at the St. Lucie Nuclear Station.

The staff inspected the CASS Program for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL AMP XI.M12. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff's inspection of the CASS Program verified that the program attributes for the CASS Program are acceptable when compared to the corresponding program attributes in GALL AMP XI.M12.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M12 in the UFSAR supplements that describe the CASS Program. This was Confirmatory Item 3.0.2.2-1. In its supplemental response dated March 28, 2003, the applicant provided revisions to the Units 1 and 2 UFSAR supplements that include references to GALL AMP X1.M12. The staff considers Confirmatory Item 3.0.2.2-1 closed.

Based on these considerations and satisfactory resolution of Confirmatory Item 3.0.2.2-1, the staff concludes that the CASS Program provides an acceptable means of managing loss of fracture toughness induced by thermal aging in RCS components made from CASS.

3.1.0.2.3 UFSAR Supplement

In Section 18.1.6 of Appendix A1 to the LRA (i.e., the UFSAR supplement summary description for AMPs), the applicant stated that the CASS Program will include a determination of the susceptibility of Class 1 CASS piping components to thermal aging embrittlement and will provide for the subsequent aging management of those components that have been identified as being potentially susceptible. The applicant also stated that aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation, and that the program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1. The applicant's UFSAR supplement summary description for the CASS Program reflects the need to implement the program prior to entering the period of extended operation. With the satisfactory resolution of Confirmatory Item 3.0.2.2-1, the staff does not see the need for changes to the UFSAR supplement descriptions for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program.

3.1.0.2.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with the RCS components fabricated from CASS will be adequately managed so that there is reasonable assurance that these subcomponents will perform their intended functions consistent with the CLB for the St. Lucie reactor units throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.3 Small Bore Class 1 Piping Inspection Aging Management Program

The applicant credits the Small Bore Class 1 Piping Inspection with managing aging effects in small bore Class 1 piping. The applicant describes this program in Section 3.1.5 of Appendix B to the LRA. Although one-time small bore piping inspection programs for RCS piping and Feedwater piping are addressed in the GALL Report, Section X1.M32, the applicant describes the program in terms of how the Small Bore Class 1 Piping Inspection meets the 10 program elements stated in the NUREG-1800. The applicant's description of the 10 program attributes for the Small Bore Class 1 Piping Inspection are provided in detail in Section 3.1.5 of Appendix B to the LRA.

3.1.0.3.1 Summary of Technical Information in the Application

The applicant states that the Small Bore Class 1 Piping Inspection will occur in the latter part of the initial operating period for St. Lucie Units 1 and 2. The timing of this inspection was established to maximize the operating time and, thus the susceptibility of Class 1 small bore piping to any age-related cracking mechanisms. This program is plant-specific. The applicant indicates that it will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to the implementation of this inspection. The applicant states that commitment dates associated with the implementation of this new program are contained in the UFSAR supplement for the program provided in Appendix A to the LRA.

In Section 3.1.5 of Appendix B to the LRA, the applicant summarizes the ability of the Small Bore Class 1 Piping Inspection to manage age-related cracking in the Class 1 small bore piping by discussing the seven program attributes for the program consistent with those recommended by the SRP-LR.

3.1.0.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.5 of Appendix B to the LRA regarding the applicant's demonstration of the Small Bore Class 1 Piping Inspection to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The Small Bore Class 1 Piping Inspection is a one-time inspection of a sample of Class 1 piping less than 4 inches in diameter. The applicant states that the sample of welds to be examined will be selected by using a risk-informed approach. The staff is therefore concerned that the risk-informed methods discussed in the LRA's description of the Small Bore Piping Inspection (Section 3.1.5 of Appendix B to the LRA) may be used as a basis for eliminating the volumetric examinations of small bore Class 1 piping joined by full-penetration butt welds. The staff addresses this concern later in its evaluation of the Detection of Aging and Monitoring and Trending program attributes for the AMP.

Commitment dates associated with the implementation of this new program are provided in Section 18.1.5 of LRA Appendix A1 for St. Lucie Unit 1 and Section 18.1.4 of LRA Appendix A2 for St. Lucie Unit 2. The staff agrees with the adequacy of the applicant's description of the scope of this program because the program focuses on implementation of an inspection of small bore Class 1 piping using volumetric examination techniques that have been demonstrated to be acceptable for detecting cracking in the components.

Preventive Actions: The applicant states that no preventive actions are applicable to this AMP. The staff agrees that an inspection-based program is designed to detect age-related cracking in the St. Lucie small bore Class 1 piping, and is on a preventive/mitigative program that is designed to preclude the occurrence of cracking.

Parameters Monitored or Inspected: Section 3.1.5 of Appendix B to the LRA states that cracking is the parameter that the Small Bore Class 1 Piping Inspection monitors. The staff has raised the issue of degradation in small bore Class 1 piping because it was concerned that current ASME Section XI surface examination requirements for inspecting full-penetration butt welds in small bore Class 1 piping may not be sufficient to detect cracking that is induced by either thermal fatigue or stress corrosion. The staff concurs with the applicant's aging effect parameter for this AMP and concludes that the Parameters Monitored or Inspected program attribute is acceptable.

Detection of Aging Effects and Monitoring and Trending: The applicant states that the volumetric examination technique chosen will permit detection and sizing of significant cracking of small bore Class 1 piping. The staff agrees with the adequacy of the examination techniques described by the applicant because this is a proven method for this type of inspection. The applicant also states that the detection of cracking will be performed using approved and qualified volumetric examination techniques, such as UT or radiography testing. The staff agrees with the adequacy of the examination techniques described by the applicant because volumetric inspection techniques, such as UT or radiology testing, have been demonstrated to be acceptable methods of detecting cracks in ASME Code Class components.

The applicant states that this is a one-time inspection, and as such, no monitoring and trending are anticipated. The risk-informed approach used for the AMP consists of two essential elements including (1) a degradation mechanism evaluation to assess the failure potential of the piping system under consideration, and (2) a consequence evaluation to assess the impact on plant safety in the event of a piping failure. In RAI B.3.1.5-1, the staff asked the applicant for the following information.

- Discuss which mechanisms will be used to determine the greatest potential failure susceptibility locations and discuss how the worst-case consequence locations for the small bore piping will be determined. Discuss how these two essential risk-informed elements will be used to quantify the susceptibility rankings of the small bore Class 1 piping within the scope of the Small Bore Class 1 Piping Inspection.

- Explain which documents or information will be used to define the sample size for the volumetric inspections that will be proposed for the small bore Class 1 piping.

In response to RAI B.3.1.5-1, dated September 26, 2002, the applicant stated that the Small Bore Class 1 Piping Inspection will occur in the latter part of the initial operating periods for St. Lucie Units 1 and 2. The applicant states that the timing of the inspection was established to maximize the operating time and, thus, the susceptibility to any age-related cracking mechanism. The inspection will incorporate the results and recommendations from industry initiatives, including applicable results from the EPRI industry initiative assembling previous guidance on nondestructive examination (NDE) methodologies and providing recommendations for specific NDE technology and variables for examination methods selected for the Small Bore Class 1 Piping Inspection. The staff concludes that this approach is reasonable and is therefore acceptable.

In response to RAI B.3.1.5-1, and as indicated in Section 18.1.5 of LRA Appendix A1 for Unit 1, Section 18.1.4 of LRA Appendix A2 for Unit 2, and Section 3.1.5 of Appendix B to the LRA, the applicant stated that FPL will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to its implementation. The report will include a description of the methodologies used to determine the greatest potential failure susceptibility locations and worst-case consequence (risk-informed) small bore Class 1 piping locations. The applicant also indicated that the report will describe the methods used to determine the sample size for the volumetric examinations proposed for the small bore Class 1 piping.

The applicant has not yet submitted the Small Bore Class 1 Piping Inspection plan to the staff for review because the applicant has not yet implemented the risk-informed methodologies for determining the small bore piping locations most susceptible to age-related cracking and for establishing the sample size for the inspection. However, the staff confirmed that the applicant has included statements, in Section 18.1.5 of LRA Appendix A1 for Unit 1 and Section 18.1.4 of LRA Appendix A2 for Unit 2, that commit the applicant to submitting the Small Bore Class 1 Piping Inspection plan, including the risk-informed methodologies for determining the sample locations and sample size for the inspections, to the NRC for review and approval.

The staff has approved risk-informed inservice inspection (RI-ISI) methods for ASME Code Class components through the relief request process for approving acceptable alternatives to the requirements of Section XI to the ASME Boiler and Pressure Vessel Code, as allowed under the provisions of 10 CFR 50.55a(a)(3)(i). However, the license renewal rule does not allow the staff to accept the elimination of SCs from AMRs based on risk-informed arguments. The application does not provide a clear indication whether the risked-informed methods within the scope of the Small Bore Class 1 Piping Inspection are methods within the scope of an RI-ISI program that is required to be submitted for review and approval under the provisions of 10 CFR 50.55a(a)(3), or simply a risk-informed susceptibility approach that will be used to establish the small bore Class 1 piping locations for volumetric examination in each unit. The staff raised the issue on small bore Class 1 piping because it was concerned that current ASME Section XI surface examination requirements for small bore Class 1 piping joined by full-penetration butt welds may not be sufficient to detect cracking that initiates in the welds as a result of thermal fatigue or stress corrosion. In Open Item 3.1.0.3-1, the staff informed the applicant that it had a concern if the risk-informed methods within the scope of the Small Bore Class 1 Piping Inspection AMP were within the scope of an RI-ISI program that would be required to be approved under the provisions of 10 CFR 50.55a(a)(3). Specifically, the staff stated that the potential exists for RI-ISI methodologies to "screen out" the volumetric examinations of the small bore Class 1 piping based on risk information, and therefore if the risk-informed methods are part of an RI-ISI program, they may be used to eliminate all of the volumetric examinations proposed for the small bore Class 1 piping components. Therefore, in Open Item 3.1.0.1-2, the staff requested confirmation of the following information from the applicant.

- The risk-informed methodologies for the Small Bore Class 1 Piping Inspection will be used only to establish the minimum number and locations of small bore Class 1 piping full-penetration butt welds to be volumetrically examined and will not be used as a basis to eliminate the volumetric examinations for the welds.

- The inspection plan for the Small Bore Class 1 Piping Inspection, when submitted under commitment item 6 of Tables 1 and 2 of Appendix D to the SER, will provide a discussion regarding what the risk-informed methodology for the AMP involves and how that methodology will be applied to determine the locations and number of small bore Class 1 piping components for inspection.

The applicant provided the following response to Open Item 3.1.0.3-1 by letter dated March 28, 2003.

> As described in LRA Appendix B Section 3.1.5 (page B-16), Small Bore Piping Inspection, a one-time volumetric examination of a sample of Class 1 piping less than 4 inches in diameter will be performed. The sample (i.e., minimum number and locations) of welds to be examined will be selected by using a risk informed susceptibility approach. This selection method will not be part of the Risk Informed – Inservice Inspection (RI-ISI) program that is approved under the provisions of 10 CFR 50.55a (a)(3). As stated in LRA Appendix A1 Section 18.1.5 (page A1-34) for St. Lucie Unit 1 and LRA Appendix A2 Section 18.1.4 (page A2-31) for St. Lucie Unit 2, FPL will provide the NRC with a report describing the small bore inspection plan prior to implementation of the inspections.
>
> This inspection plan will confirm that the risk informed methodologies for the Small Bore Class 1 Piping Inspection will only be used to establish the minimum number and locations of the small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. This information will be included as part of the UFSAR supplement summary descriptions for the Small Bore Class 1 Piping Inspection Program as described in the FPL response to Confirmatory Item 3.1.0.3-1.

The applicant's response ensures that the risk-informed methodology for the AMP will not be used as a basis for eliminating the volumetric inspections of small bore Class 1 piping and that the staff will be provided with an opportunity to review the risk-informed methodology when the inspection plan for the Small Bore Class 1 Piping Inspection is submitted. The applicant's response resolves the concerns raised by the staff. The staff considers Open Item 3.1.0.3-1 closed.

Acceptance Criteria: The applicant states that any cracks identified will be evaluated and, if appropriate, entered into the Corrective Action Program. The applicant also states that the evaluation of the inspection results may result in additional examinations consistent with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff finds this approach acceptable because industry standards will be used in the acceptance criteria.

Operating Experience: The applicant describes this one-time inspection as a new activity which will use techniques with demonstrated capability and a proven industry record to detect piping weld and base material flaws. Effective and proven volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel. Results and recommendations from industry initiatives will be incorporated into the inspection. The staff finds this approach acceptable because cracking of small bore Class 1 piping has not been prevalent in the industry and a one-time inspection program is adequate based on industry experience to date.

3.1.0.3.3 UFSAR Supplement

The applicant provides summary descriptions for the Small Bore Class 1 Piping Inspection AMP in Section 18.1.5 of LRA Appendix A1 for St. Lucie Unit 1 and Section 18.1.4 of LRA Appendix A2 for St. Lucie Unit 2. The applicant states that a volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. The applicant also states that this is a one-time inspection that will address Class 1 piping less than 4 inches in diameter. On the basis of the results of these inspections, the applicant will determine the need for additional inspections or programmatic corrective actions. The applicant states that it will provide the NRC with a report describing the inspection plan prior to its implementation and that the inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1. The contents of these sections are consistent with the description provided in Section 3.1.5 of Appendix B to the LRA and reflect the need for the applicant to submit the inspection plan and risk-informed methodology for the Small Bore Class 1 Piping Inspection to the staff for review and approval prior to implementation of the inspection.

The staff considers the risk-informed program for the small bore Class 1 piping to be an alternative to the ISI requirements of Section XI of the ASME Boiler and Pressure Vessel Code for ASME Code Class 1 components. The applicant is required to submit this program under the provisions of 10 CFR 50.55a(a)(3) for approval of alternatives to Section XI of the ASME Boiler and Pressure Vessel Code. The staff informed the applicant that the UFSAR supplements describing the Small Bore Class 1 Piping Inspection should be revised to include the information provided in response to Open Items 3.1.0.3-1 parts 1 and 2. This was Confirmatory Item 3.1.0.3-1.

The applicant provided the following response to Confirmatory Item 3.1.0.3-1 by letter dated March 28, 2003.

> St. Lucie UFSAR Supplements, LRA Appendix A1 Section 18.1.5 for Unit 1 and LRA Appendix A2 Section 18.1.4 for Unit 2 are replaced in their entirety by the following paragraphs:
>
> Unit 1 Appendix A1, Section 18.1.5, Small Bore Class 1 Piping Inspection:
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>> A volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. This one-time inspection will address Class 1 piping less than 4 inches in diameter. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. FPL

will provide a report describing this inspection plan prior to its implementation. The inspection plan will confirm that the risk-informed methodologies will only be used to establish the minimum number and locations of small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1.

Unit 2 Appendix A2, Section 18.1.4, Small Bore Class 1 Piping Inspection:

> A volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. This one-time inspection will address Class 1 piping less than 4 inches in diameter. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. FPL will provide a report describing this inspection plan prior to its implementation. The inspection plan will confirm that the risk-informed methodologies will only be used to establish the minimum number and locations of small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 2.

The applicant's response to Confirmatory Item 3.1.0.3-1 also provided revised UFSAR supplements that incorporated descriptions of the inspection plan and risk-informed methodology information requested by the staff in Open Item 3.1.0.3-1. The staff verified that the applicant's response is acceptable. The staff considers Confirmatory Item 3.1.0.3-1 closed.

3.1.0.3.4 Conclusions

The staff has reviewed the information provided in Section 3.1.5 of Appendix B to the LRA, Section 18.1.5 of LRA Appendix A1 for St. Lucie Unit 1, and Section 18.1.4 of LRA Appendix A2 for St. Lucie Unit 2, as supplemented by the applicant's response to RAI B.3.1.5-1, dated September 26, 2002, and responses to Open Item 3.1.0.1-3 and Confirmatory Item 3.1.0.1-3, dated March 28, 2003. On the basis of this review, as set forth above, the staff concludes that the effects of aging associated with small bore Class 1 piping components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.4 Steam Generator Integrity Program

3.1.0.4.1 Summary of Technical Information in the Application

In Section 3.1.6. of the LRA, the applicant identifies that aging management of SG tubes will be managed by the Steam Generator Integrity Program which is discussed in Section 3.2.13 of Appendix B to the LRA.

The applicant states that the Steam Generator Integrity Program is consistent with the 10 attributes of the AMP, XI.M19, "Steam Generator Tube Integrity," in the GALL Report. In addition, the program scope includes the Unit 2 SG tube support lattice bars. The Steam

Generator Integrity Program also credits sludge lancing as a preventive action for secondary-side SG tube degradation and tube bundle flushing to minimize FAC of the Unit 2 carbon steel tube support lattice bars.

The applicant states that the Steam Generator Integrity Program has been effective in ensuring detection of the aging effects of cracking and loss of material in SG tubes. The program is structured to meet NEI 97-06, "Steam Generator Program Guidelines," which references several EPRI guidelines. These EPRI guidelines include SG examination, tube integrity assessments, primary and secondary water chemistry, primary-to-secondary leakage, in-situ pressure testing, and tube plug assessment. Although the applicant did not explicitly discuss this in the LRA, the Steam Generator Integrity Program must also satisfy the SG surveillance requirements in the St. Lucie Units 1 and 2 technical specifications.

3.1.0.4.2 Staff Evaluation

The staff reviewed the Steam Generator Integrity Program to determine whether the applicant has demonstrated that the effects of aging on the SG components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). The 10 program elements in the GALL Report, AMP XI.M19, "Steam Generator Tube Integrity," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects on SG components.

The applicant evaluated the current SG inspection activities against industry recommendations provided by EPRI via NEI 97-06 and the SG suppliers. The applicant states that the effectiveness of the program is demonstrated by the operating experience and inspection results. The Steam Generator Integrity Program provides assurance that tube wear, pitting corrosion, general corrosion, crevice corrosion, PWSCC, intergranular attack (IGA), and intergranular stress-corrosion cracking (IGSCC) of components are managed and that the intended functions of the SG will be maintained consistent with the CLB during the period of extended operation. The applicant retains the program description of the Steam Generator Integrity Program, and the descriptions of the program's 10 elements, on record at the St. Lucie nuclear station.

The staff inspected the Steam Generator Integrity Program for acceptability and compared the program's 10 elements to those described in the GALL Report, AMP XI.M19. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. On the basis of these considerations, the staff finds that the Steam Generator Integrity Program will provide an acceptable means of managing the aging effects of SG components.

On the basis of its AMP evaluations, the staff concludes that the AMP is acceptable for managing the pertinent aging effects and providing assurance that the intended functions of the SG components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M19 in the UFSAR supplements' descriptions of this AMP. This was Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP X1.M19. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.1.0.4.3 UFSAR Supplement

The staff reviewed Section 18.2.13 of Appendix A1 and Section 18.2.12 of Appendix A2 of the UFSAR supplement of the LRA. The staff concluded that the information provided in the UFSAR supplements for aging management of SG discussed above is equivalent to the information in Table 3.1-2 of NUREG-1800, and, therefore, provides an adequate summary of the program activities, required by 10 CFR 54.21(d).

3.1.0.4.4 Conclusion

The staff concludes that the applicant has demonstrated that the aging effects associated with the SGs will be adequately managed so that these components will perform their intended functions in accordance with the CLB for the period of extended operation, as required by 10 CFR 52.21(a)(3). The staff concludes that the information provided in the UFSAR supplements for aging management of the SGs satisfies 10 CFR 54.21(d).

3.1.0.5 Reactor Vessel Integrity Program

The applicant credits the Reactor Vessel Integrity Program (Section 3.2.12 of Appendix B to the LRA) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. The staff's review of this AMP is provided below.

The applicant described its Reactor Vessel Integrity Program in Section 3.2.12 of Appendix B to the LRA. The St. Lucie Units 1 and 2 Reactor Vessel Integrity Program is designed to manage RV irradiation embrittlement and encompasses the subprograms listed below.

- reactor vessel surveillance capsule removal and evaluation
- fluence and uncertainty calculations
- monitoring effective full power year
- pressure/temperature limit curves

These aging management subprograms support the applicant's RV neutron embrittlement TLAA (Section 4.2.1 of the LRA) which includes analyses of the upper-shelf energy (USE) pressurized thermal shock (PTS), and pressure-temperature (P-T) limits. The staff's evaluation of theTLAA is provided in Section 4.2 of this SER.

Criteria of the first 40 years are specified in 10 CFR Part 50, Appendix H, "Reactor Vessel Materials Surveillance Program Requirements," which concerns monitoring changes in the fracture toughness of ferritic materials in the reactor beltline region caused by exposure to neutron irradiation and thermal environments. Appendix H requires that the surveillance program design and withdrawal schedule meet the requirements of American Society for

Testing and Materials (ASTM E 185), "Standard Practice for Conducting Surveillance Tests for Light-Water-Cooled Nuclear Power Vessels."

Revision 2 of Regulatory Guide (RG) 1.99, "Radiation Embrittlement of Reactor Vessel Materials," describes general procedures acceptable to the NRC staff for calculating the effects of neutron irradiation embrittlement of the low-alloy steels used for light-water-cooled RVs. Surveillance data from the Appendix H program are used in RG 1.99, Revision 2, calculations, if applicable. The four subprograms are reviewed separately in the following paragraphs.

3.1.0.5.1 Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram

Technical Information in the Application

The applicant described the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram in Appendix B, Section 3.2.12.1, of the LRA. The staff reviewed the subprogram to determine whether the applicant has demonstrated that the aging effects covered by the subprogram will be adequately managed during the period of extended operation, as required by CFR 54.21(a)(3).

Staff Evaluation

The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all SCs subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Reactor Vessel Integrity Program includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of the test program for these materials involves the measurement of irradiation effects by pre-irradiation and post-irradiation testing of Charpy V-notch and tensile samples. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore, acceptable to the staff.

Preventive Actions: No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation of the RV. The Reactor Vessel Integrity Program is a surveillance monitoring program designed to monitor for property changes in materials and for loss of fracture toughness in the materials used to fabricate the RVs and to comply with the Reactor Vessel Material Surveillance Program capsule withdrawal and testing requirements of 10 CFR Part 50, Appendix H. The program uses Charpy V impact testing of the surveillance capsule specimens to monitor changes (losses) in fracture toughness in the RV beltline materials. Surveillance programs implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, are not designed to prevent or mitigate aging effects before their occurrence. The staff, therefore, concludes that no preventive actions are needed. The staff finds this acceptable because the program is not designed to be a preventive or mitigative program for precluding aging effects prior to their occurrence.

Parameters Monitored or Inspected: The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram monitors reduction of fracture toughness and tensile strength, as measured by Charpy V-notch and tensile test results for irradiated specimens for RV plate and weld materials. Additionally, accumulated neutron fluence is monitored utilizing surveillance capsule dosimetry. Tables 5.4-3 and 5.3-9 of Appendices A1 and A2 to the LRA include the changes to the surveillance capsule schedules for Units 1 and 2 to address the extended period of operation.

In regards to the surveillance capsule removal schedule, the applicant indicates that the fourth capsule in Unit 1 will be withdrawn at 38 effective full-power years (EFPY) with a predicted neutron fluence of 4.4×10^{19} neutrons per square centimeter (n/cm^2). In Table 4.2-3 of the LRA, the applicant indicates that the peak end of life (EOL) fluence for Unit 1 is 4.68×10^{19} n/cm, which is greater than the predicted fluence to be received on the fourth capsule for St. Lucie Unit 1. For Unit 2, the applicant indicates that the fourth capsule will be withdrawn at 44 EFPY with a predicted neutron fluence of 4.56×10^{19} n/cm^2. In Table 4.2-4 of the LRA, the applicant indicates that the peak EOL fluence for Unit 2 is 4.89 x 10 19 n/cm, which is also greater than the predicted fluence to be received on the fourth capsule for St. Lucie Unit 2.

In accordance with the latest edition of ASTM E 185 endorsed through Appendix H to 10 CFR Part 50, it is recommended that, for current 40-year practice the last capsule to be removed should receive a fluence not less than once or greater than twice the peak EOL fluence. Therefore, the applicant was requested to provide updated capsule removal schedules that reflect capsules to be withdrawn with predicted fluences between one and two times the peak EOL fluences for the extended period of operation of St. Lucie Units 1 and 2. The staff generated Open Item 3.1.0.5-1 to track this item.

In its March 28, 2003, response to Open Item 3.1.0.5-1, the applicant indicated that the predicted 60-year EOL peak fluence for St. Lucie Unit 1 is 4.24×10^{19} n/cm^2, based on 52 EFPYs of operation, and the predicted 60-year EOL peak fluence for St. Lucie Unit 2 is 4.56×10^{19} n/cm^2, based on 55 EFPYs of operation. As indicated in the applicant's LRA reactor pressure vessel surveillance capsule withdrawal schedules, the final surveillance capsule for St. Lucie Unit 1 is to be withdrawn at a fluence of 4.4×10^{19} n/cm^2, and the final St. Lucie Unit 2 capsule is to be withdrawn at a fluence of 4.56×10^{19} n/cm^2. Based on these values, the staff was able to verify that the last capsules to be withdrawn at St. Lucie Units 1 and 2 would satisfy the recommendation of the latest endorsed edition of ASTM E 185. Therefore, the staff considers Open Item 3.1.0.5-1 to be closed.

Detection of Aging Effects: The applicant states that the effects of aging will be detected based on the data obtained in the monitoring and trending effort from the Reactor Vessel Material Surveillance Program. This will be done by quantifying the change in temperature at 30 ft-lb energy from unirradiated and irradiated specimens. The staff finds this approach to be acceptable since it will determine the increase in reference temperature due to irradiation, and it is in accordance with the requirements of 10 CFR Part 50, Appendix H.

Acceptance Criteria: The acceptance criteria for fracture toughness are that the reference temperature for PTS (RT_{pts}) must be below the screening criterion of 270 °F for plates, forgings, and longitudinal welds, and below 300 °F for circumferential welds. The staff finds this approach acceptable since it complies with the requirements of the PTS rule stated in 10 CFR 50.61. The acceptance criterion for Charpy USE is that the USE remains above

50 foot pounds (ft-lbs). For materials for which Charpy USE falls below 50 ft-lbs, there are provisions in Appendix G to 10 CFR Part 50 that must be followed. Specifically, the applicant must demonstrate that during the period of extended operation the Charpy USE has a margin of safety against fracture equivalent to that specified in Section XI of the ASME Boiler and Pressure Vessel Code. The staff finds this acceptable because it complies with the requirements stated in 10 CFR Part 50, Appendix G.

Operating Experience: The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram meets the requirements stated in 10 CFR Part 50, Appendix H, and has been in effect since initial plant startup. The applicant has updated this program over the years and has gained experience in addressing reduction in fracture toughness. The applicant updates the Units 1 and 2 P-T limit curves using the results from the vessel surveillance capsule specimen evaluations. The applicant evaluated the Units 1 and 2 RT_{pts} values that are below the screening criteria in 10 CFR 50.61. Also, the applicant evaluated the USE values that remain above 50 ft-lbs, which is in accordance with 10 CFR Part 50, Appendix G. Therefore, the staff finds the applicant's description of operating experience acceptable.

UFSAR Supplement. In Section 18.2.12.1 of Appendix A1 and Section 18.2.11.1 of Appendix A2 of the LRA, the applicant describes the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprograms for Units 1 and 2. The subprogram descriptions are consistent with the material contained Section 3.2.12.1 of the Appendix B and are therefore acceptable to the staff.

Conclusions. The staff has reviewed the information provided in Section 3.2.12.1 of Appendix B to the LRA and the summary description of the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram in Section 18.2.12.1 of Appendix A1 and Section 18.2.11.1 of Appendix A2 of the UFSAR supplement for Units 1 and 2, respectively. On the basis of its review of the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram, the staff finds that the continued implementation of this AMP provides reasonable assurance that the reduction in fracture toughness of RV beltline region materials will be adequately managed so that the intended functions of the RV will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR Part 54.21(a)(3).

3.1.0.5.2 Fluence and Uncertainty Calculations Subprogram

Summary of Technical Information in the Application. The applicant described the Fluence and Uncertainty Calculations Subprogram in Appendix B, Section 3.2.12.2, of the LRA. The staff reviewed the subprogram to determine whether the applicant demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicates that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program pursuant to 10 CFR Part 50, Appendix B, and cover all SCs subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Fluence and Uncertainty Calculations Subprogram includes the belt line materials defined in 10 CFR 50.61(a)(3). The scope of this subprogram for these materials involves calculations to provide accurate predictions of the actual RV neutron fast fluence values for use in the development of the P-T limit curves and PTS calculations. This is consistent with the scope of the RV integrity programs required to be implemented in accordance with the requirements stated in 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

Preventive Actions: There are no preventive or mitigative actions associated with the Fluence and Uncertainty Calculations Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: The monitored parameters are the RV neutron fast fluence values, which are predicted based on analytical models meeting the requirements of draft NRC RG DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," which is consistent with RG 1.190. The monitored parameters are benchmarked using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. Benchmarking has been supplemented by draft RG DG-1053 cavity dosimetry. The applicant indicates that the determination of fluence is based on both calculations and measurements. The applicant's methodology includes calculating fluence predictions and qualifying the calculational methodology by actual fluence measurements.

The applicant has implemented a Pressure Vessel Radiation Surveillance Program at St. Lucie Units 1 and 2, as discussed above. The program is based on ASTM E185. Six material test capsules were placed in each unit. The program provides for the periodic removal of capsules for evaluation throughout the plant life. The present database at St. Lucie includes data evaluated from three Unit 1 capsules and two Unit 2 capsules. The results from these measurements, the Units 1 and 2 operating histories, and calculated power distributions make up the database for the fluence calculations.

The most recent data calculations use discrete ordinates radiation transport for the neutron transport calculation, a Discreet Ordinates Radiation Transport post-processor code named DOTSOR for geometry conversion, and Bugle-96. The power distributions are based on the Westinghouse Advanced Nodal Code. The staff finds the applicant's fluence calculation methodology acceptable because it is consistent with the recommendations of DG-1053 and RG 1.190.

Detection of Aging Effects: Fluence values are determined by actual calculations of vessel fluence, empirical results from Charpy V-notch tests of irradiated specimens, and capsule dosimetry in accordance with the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. The staff finds this approach to be acceptable because these parameters are sufficient for determining predicting fluence values.

Monitoring and Trending: Neutron fluence and uncertainty calculations are performed to predict the fast neutron fluence. These calculations are verified using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. The staff finds this approach acceptable because dosimetry results can be used to verify calculations to predict neutron fluence.

Acceptance Criteria: Based on the calculations, the RV fluence uncertainty values are to be within 20 percent. Calculated fluence values for fast neutrons (above 1 MeV) are compared with measured values. This methodology represents a continuous validation process to ensure that no biases have been introduced and that the uncertainties remain comparable to the reference benchmarks. The staff finds this approach to be acceptable because it is consistent with DG-1053 and RG 1.190.

Operating Experience: The applicant performed neutron fluence and uncertainty calculations for Units 1 and 2 in accordance with the guidelines of DG-1053 and validated the results using data obtained from capsule dosimetry. Because the calculated fluence values were compared to measured values, the staff finds that the applicant's description of operating experience supports the attributes of the subprogram described above.

UFSAR Supplement. Section 18.2.12.2 of Appendix A1 and Section 18.2.11.2 of Appendix A2 of the LRA provide the applicant's Description of the Fluence and Uncertainty Calculations Subprograms at Units 1 and 2. The subprogram descriptions are consistent with the material contained in Section 3.2.12.2 of Appendix B and are therefore acceptable to the staff.

Conclusions. The staff has reviewed the information provided in Section 3.2.12.2 of Appendix B to the LRA, and the summary description of the Fluence and Uncertainty Calculations Subprogram in Section 18.2.12.2 of Appendix A1 and Section 18.2.11.2 of Appendix A2 of the UFSAR supplements for Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Fluence and Uncertainty Calculations Subprogram so that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.3 Monitoring Effective Full-Power Years Subprogram

Summary of Technical Information in the Application. The applicant described the Monitoring Effective Full- Power Years Subprogram in Appendix B, Section 3.2.12.3, to the LRA. The staff reviewed the subprogram in Appendix B, Section 3.2.12.3, to the LRA to determine whether the applicant had demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all SCs subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Monitoring Effective Full-Power Years Subprogram includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of this program is to accurately monitor and tabulate the accumulated operating time experienced by the RV and to ensure that the P-T limit curves. The scope of this program supports the requirements of

10 CFR Part 50, Appendix G, and is therefore acceptable to the staff.

Preventive Actions: There are no preventive or mitigative actions associated with the Pressure-Temperature Limit Curves Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: This subprogram monitors and tabulates the accumulated operating time experienced by St. Lucie Units 1 and 2 RVs. The EFPYs of plant operation are based on core thermal power. EFPY values are derived by accumulating time at the measured thermal power relative to rated thermal power. The staff finds this approach to be acceptable because it uses appropriate plant parameters to calculate EFPYs of operation.

Detection of Aging Effects: EFPY calculations are utilized for the prediction of fast neutron fluence and the determination of the reduction of fracture toughness of RV critical materials. The staff finds this approach to be acceptable because it supports the requirements of 10 CFR Part 50, Appendix G.

Monitoring and Trending: This subprogram monitors the RV EFPYs to be used in predicting the fast neutron fluence. Each St. Lucie unit is monitored to determine the EFPYs of operation. These data are used to validate the applicability of the P-T limit curves for the next operating cycle. The staff finds this approach to be acceptable because it supports the requirements of 10 CFR Part 50, Appendix G.

Acceptance Criteria: Calculated EFPYs shall not exceed the technical specification limits for the validity of the P-T limit curves. The staff finds this acceptable because it is consistent with the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

Operating Experience: The EFPY calculations are used to verify the continued validity of the P-T limit curves. Plant-specific experience has proven this to be an effective process. Therefore, the staff finds that the applicant's description of operating experience supports the attributes of the subprogram described above.

<u>UFSAR Supplement</u>. Section 18.2.12.3 of Appendix A1 and Section 18.2.11.3 of Appendix A2 to the LRA provide the applicant's UFSAR supplement for the Monitoring Effective Full-Power Years Subprogram at St. Lucie Units 1 and 2, respectively. The subprogram descriptions are consistent with the material contained in Section 3.2.12.3 of Appendix B and are therefore acceptable to the staff.

<u>Conclusions</u>. The staff has reviewed the information provided in Section 3.2.12.3 of Appendix B to the LRA, and the summary description of the Monitoring Effective Full-Power Years Subprogram in Section 18.2.12.3 of Appendix A1 and Section 18.2.11.3 of Appendix A2 to the UFSAR supplement for St. Lucie Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Monitoring Effective Full-Power Years Subprogram so that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.4 Pressure-Temperature Limit Curves Program

Summary of Technical Information in the Application. The applicant described the Pressure-Temperature Limit Curves Subprogram in Appendix B, Section 3.2.12.4, to the LRA. The staff reviewed the subprogram in Appendix B, Section 3.2.12.4, to the LRA to determine whether the applicant has demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all SCs subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Pressure-Temperature Limit Curves Subprogram includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of this subprogram is to establish P-T limit curves for the normal operating, inservice leak test, and hydrostatic test limits for the RCS, as applicable to the St. Lucie Units 1 and 2 pressure vessels. The curves are used to limit operations based on the material properties of the vessel caused by neutron irradiation. This is consistent with the scope of the Pressure-Temperature Limit Curves Subprogram, required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix G, and is therefore acceptable to the staff.

Preventive Actions: There are no preventive or mitigative actions associated with the Pressure-Temperature Limit Curves Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: P-T limit curves are generated assuming that a 1/4 Timeless (1/4T) surface flaw exists and using the fracture mechanics methodology in ASME Section XI, Appendix G. The P-T curves are determined by using bounding input heatup and cooldown transients. The staff finds this approach to be acceptable because the P-T limit curves are generated to meet the requirements in Appendix G to Section XI of the ASME Code, as required by Appendix G to 10 CFR Part 50.

Detection of Aging Effects: The P-T limit curves are not provided for the detection of aging effects, nor did the staff identify such a need. Rather, the P-T limit curves prevent or minimize the potential for damage to the RV materials.

Monitoring and Trending: The P-T limit curves are valid for a period expressed in EFPY in the technical specifications. These curves are updated prior to exceeding the EFPY for which they are valid. The time period for updating P-T limit curves may be adjusted if conditions such as changes in fuel type or fuel loading pattern occur. The staff finds this approach acceptable because the P-T limit curves are updated prior to exceeding the applicable EFPY, which is in accordance with the requirements of 10 CFR Part 50, Appendix G.

Acceptance Criteria: The P-T limit curves are valid for a specified number of EFPYs. The curves must be updated before this time period is exceeded. The staff finds this approach acceptable since the validity of the curves is monitored and the P-T limit curves are updated prior to exceeding the applicable EFPY, which is in accordance with the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

Operating Experience: FPL utilizes P-T limit curves for St. Lucie Units 1 and 2 that are updated using the results of data obtained from surveillance capsules. These curves are updated prior to exceeding the EFPYs for which they are valid. The P-T limit curves provide sufficient operating margin, while preventing or minimizing the effects of reduced fracture toughness caused by neutron irradiation. Therefore, the staff finds that the applicant's description of operating experience supports the attributes of the subprogram described above.

UFSAR Supplement. Section 18.2.12.4 of Appendix A1 and Section 18.2.11.4 of Appendix A2 to the LRA provide the applicant's UFSAR supplement for the Pressure-Temperature Limit Curves Subprogram at St. Lucie Units 1 and 2, respectively. The subprogram descriptions are consistent with the material contained in Section 3.2.12.4 of Appendix B and are therefore acceptable to the staff.

Conclusions. The staff has reviewed the information provided in Section 3.2.12.4 of Appendix B of the LRA, and the summary description of the Pressure-Temperature Limit Curves Subprogram in Section 18.2.12.4 of Appendix A1 and Section 18.2.11.4 of Appendix A2 to the UFSAR supplement for St. Lucie Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Pressure-Temperature Limit Curves Subprogram so that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.5 Conclusions

Pertaining to updated capsule withdrawal schedules to account for the peak EOL neutron fluence, the staff concludes that the applicant has demonstrated through the four subprograms of the Reactor Vessel Integrity Program that the aging effects associated with the RV components will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the program activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.1.0.6 Fatigue Monitoring Program

The Fatigue Monitoring Program (FMP) is described in Section 3.2.7 of Appendix B to the LRA. This AMP provides for condition monitoring of components within several RCS systems that are within the scope of license renewal. The staff reviewed the LRA to determine whether the applicant has demonstrated that the FMP will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.6.1 Summary of Technical Information in the Application

Section 3.2.7 of Appendix B to the LRA describes the FMP as a plant-specific program that is designed to track cyclic and transient occurrences to ensure that RCPB components remain within ASME Code, Section III, fatigue limits. The applicant refers to the FMP as a confirmatory program, rather than an actual AMP because the program only monitors the number of significant plant transients to assure that the number of transients assumed in the design fatigue analyses are not exceeded.

3.1.0.6.2 Staff Evaluation

The staff reviewed the FMP to determine whether it will assure that the fatigue design limits are not exceeded during the period of extended operation in accordance with the requirements in 10 CFR 54.21(a)(3). The staff evaluated the program against the following 10 elements that are described in Appendix A to NUREG 1800–program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the program includes the RVs, RV internals, pressurizers, SGs, reactor coolant pumps (RCPs), and Class 1 RCS piping. The program tracks the number of design cycles to ensure that these components remain within their design limits. The staff considers the scope of the program, which includes the RCS components with ASME Code fatigue analyses, acceptable.

Preventive Actions: The applicant identified the cycle counting procedure as the preventive action for this program because, coupled with corrective actions, it prevents against exceeding the fatigue limits. The staff considers counting of design cycles to be an acceptable preventive action.

Parameters Inspected or Monitored: The parameters monitored are the cycles of design transients that cause significant fatigue usage in the Class 1 design analyses. The staff considers this monitoring appropriate because the program objective is to ensure that the design analyses remain valid during the period of extended operation.

Detection of Aging Effects: The program monitors design transients that cause significant fatigue usage in the fatigue analysis of components and uses the information to assure that the fatigue design limits are not exceeded. This provides assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff considers this monitoring appropriate.

Monitoring and Trending: The applicant will use administrative procedures for logging design cycles. As stated previously, the program monitors the design transients that cause significant fatigue usage in the fatigue analysis of the components to assure that the fatigue analyses of record remain valid during the period of extended operation. The staff finds this program element acceptable

Acceptance Criteria: The applicant specified the maximum number of design cycles in the plant administrative procedures. The applicant indicates that the plant procedures require administrative action of the actual cycle count reaches 80 percent of any design cycle limit. The staff considers this criterion acceptable.

Operating Experience: The applicant's program involves tracking transients used in the design of these components. The applicant, indicates that an independent assessment of the program was performed. According to the applicant the assessment concluded that the administrative procedure accurately identifies and classifies fatigue-sensitive design cycles. The staff finds the applicant has adequately addressed operating experience.

3.1.0.6.3 UFSAR Supplement

The staff reviewed the summary description of the FMP provided in the UFSAR supplements in Appendix A to the LRA. The staff determined that Appendix A to the LRA provides a sufficient summary description of the FMP to satisfy the requirements of 10 CFR 54.21(d).

3.1.0.6.4 Conclusions

The applicant references the FMP in its discussion of the fatigue TLAAs as a confirmatory program to assure that design fatigue limits are not exceeded during the period of extended operation. The staff considers the applicant's program, which monitors the number of plant transients that cause significant fatigue usage in the Class 1 design analyses, an acceptable method to manage the fatigue usage of the RCS components within the scope of the program. The staff concludes that the FMP will adequately manage the thermal fatigue of RCS components at St. Lucie Units 1 and 2 so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7 Reactor Vessel Internals Inspection Program

The applicant describes the Reactor Vessel Internals Inspection Program in Section 3.1.4 of Appendix B to the LRA. The applicant credits this AMP to manage specific RVI aging effects for Units 1 and 2. The staff reviewed the applicant's description of the program to determine whether the applicant has demonstrated that it will adequately manage the applicable effects of aging in RVIs during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7.1 Summary of Technical Information

The purpose of the Reactor Vessel Internals Inspection Program is to monitor the condition of RVIs in order to assure that the applicable aging effects will not result in loss of intended functions during the period of extended operation. The applicant stated that different aging effects will affect various RVIs components. The aging effects addressed by this AMP include (1) cracking, (2) reduction in fracture toughness, (3) loss of mechanical closure integrity, and (4) dimensional changes. The applicant stated that this AMP will supplement the Chemistry Control Program and Inservice Inspection Program to assure that aging effects potentially requiring additional management will not result in loss of intended functions of the RVIs during the period of extended operation.

3.1.0.7.2 Staff Evaluation

The staff's evaluations of seven of the program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes corrective actions, confirmation process, and administrative controls) for the Reactor Vessel Internals Inspection Program is documented in Section 3.0.4 of this SER.

Program Scope: The applicant stated that the scope of the Reactor Vessel Internals Inspection Program consists of the stainless steel upper guide structure support plate, fuel alignment plate, fuel alignment plate guide lugs, control element assembly (CEA) instrument tubes, CEA shroud base, incore instrumentation support plate and guide tubes, holddown ring, CEA extension shaft guides, fuel alignment plate guide lug inserts, core support barrel, core support barrel upper flange, alignment keys, patches, core support plate, core shroud assemblies, fuel alignment pins, core support columns, CEA shroud bolts, fuel alignment plate guide lug bolts, insert bolts, core shroud tie rods and snubber bolts, CASS flow bypass inserts, single tube CEA shrouds, and Unit 1 core support columns. The staff concludes that the applicant's scope for the Reactor Vessel Internals Inspection Program identified the appropriate RVI components requiring aging management.

Preventive Actions: The applicant stated that there are no preventive/mitigative actions associated with this program, nor did the staff identify a need for such. The Reactor Vessel Internals Inspection Program is a surveillance monitoring program and, as such, is not designed to prevent or mitigate the aging effects for the RVI components prior to their occurrence. However, the staff noted that the applicant will control the reactor coolant water chemistry by the implementation of the Chemistry Control Program.

Parameters Monitored or Inspected: The Reactor Vessel Internals Inspection Program monitors cracking and reduction of fracture toughness on the RVI accessible parts and loss of mechanical closure integrity of RVI bolted joints. In addition, visual inspections will also be performed to detect dimensional changes induced by void swelling.

The program requires the applicant to perform visual inspections of the RVI components for the purpose of detecting loss of material due to wear or cracking initiated by fatigue, SCC or irradiation-assisted stress-corrosion cracking (IASCC). The Reactor Vessel Internals Inspection Program requires the applicant to inspect CASS or highly irradiated stainless steel RVI components for cracks to ensure that the components will not fail catastrophically as a result of fast fracture. In the case of the highly irradiated stainless steel RVI components, visual inspections will also be used to detect dimensional changes induced by void swelling, as noted above.

The staff concludes that this attribute for the Reactor Vessel Internals Inspection Program is acceptable because the program directly monitors for flaws (cracking and loss of material) that may occur in the RVI. The program also indirectly monitors for loss of mechanical closure integrity and dimensional changes that may occur in highly irradiated RVI components.

Detection of Aging Effects: The aging effects of IASCC on selected RVI parts will be detected by the performance of VT-1 examinations capable of detecting a 3/32-inch character against a grey background. Cracking is expected to initiate at the surface and will be detectable by the VT-1 visual examination.

Additionally, the applicant indicated that certain RVI components that are fabricated from wrought stainless steel or CASS will be selected as leading locations for IASCC based on the highest projected combination of fluence and stress. For these RVI parts, an enhanced VT-1 examination, capable of detecting 0.5 mil wire against a gray background, will be performed. If IASCC is identified by this inspection, accessible areas of additional RVI parts potentially susceptible to IASCC will be inspected utilizing this enhanced VT-1 examination. The staff finds this approach acceptable because enhanced VT-1 examinations are capable of detecting aging effects associated with IASCC.

Monitoring and Trending: The VT-1, and in some cases enhanced VT-1, examinations of selected RVI parts will be performed one time for each unit during the period of extended operation. Based on the results of this examination, additional examinations and/or repairs, if required, will be scheduled.

The inspections will correspond with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program RVI. In order to develop a baseline for the extended period of operation, FPL plans to perform the first of these RVI inspections early in the renewal period on St. Lucie Unit 1, since it is expected to be the unit leading in fluence at that time. Unless the Unit 1 inspection results dictate otherwise, the St. Lucie Unit 2 inspection will be conducted early in the second 10-year inspection interval in its license renewal term.

The applicant indicated that it has access to the EPRI Materials Reliability Program products related to RIVs as they are completed. The Materials Reliability Program strategy is to evaluate potential aging mechanisms and their effects on specific RVI components by evaluating parameters such as fluence, material properties, stress, etc. Critical locations can thereby be identified and tailored inspections can be conducted on either an integrated industry or plant-specific basis. With respect to dimensional changes due to void swelling, FPL indicated that as the void swelling "white paper", which will include available data and effects on RVIs is completed, FPL will evaluate the results and factor them into the Reactor Vessel Internals Inspection Program, as applicable. In the LRA, the applicant commits to supplement the Reactor Vessel Internals Inspection Program and to submit an integrated report to the NRC prior to the end of the initial operating term of St. Lucie Unit 1. The report will summarize the understanding of the aging effects applicable to the RVIs and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks, and acceptance criteria.

Acceptance Criteria: The applicant indicated that acceptance criteria will be developed prior to the visual examination. For RVI components fabricated from CASS, and hence subject to thermal embrittlement, concurrent exposure to high neutron fluence levels may result in a synergistic effect wherein the service-degraded fracture toughness is reduced from the levels predicted independently for either of the mechanisms. Therefore, components determined to be subject to thermal embrittlement require an additional consideration of the neutron fluence of the component to determine the full range of degradation mechanisms applicable for the component. The applicant will evaluate the degree of loss of fracture toughness associated with thermal embrittlement and embrittlement due to neutron radiation exposure, as appropriate. The results of this evaluation will directly affect the acceptable flaw size which may be left in service when detected by the enhanced VT-1 examinations. The staff finds that the applicant's approach is consistent with the staff's ISG, "Thermal Embrittlement of Cast Austenitic Stainless Steel Components," dated May 2000. That is, enhanced VT-1 inspections, when coupled with acceptance criteria that account for all degradation mechanisms which may lead to loss of fracture toughness, are considered an acceptable supplemental examination as described in IWA-2210 of Section XI of the ASME Code. Therefore, the staff finds the applicant's description of this attribute acceptable because it is in accordance with the Interim Staff Guidance.

Cracks of RVI components fabricated from stainless steel and CASS will be evaluated for determination of the need and method of repair or replacement. The staff finds this approach acceptable because it is consistent with the acceptance criteria stated for Section XI.M16, "PWR Vessel Internals," of the GALL Report.

Operating Experience: The VT-1, and in some cases, enhanced VT-1 examinations to be performed by this program are inspections with demonstrated capability and a proven industry record of detecting potential cracking. Therefore, the staff finds that the applicant's description of operating experience supports the attributes of the program described above.

Conclusions. The staff finds that this AMP will adequately manage cracking, loss of preload, dimensional changes, and reduction in fracture toughness of RV internals, such that the intended function(s) of the RVIs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7.3 UFSAR Supplement

Sections 18.1.3 of Appendix A and Section 18.1.4 of Appendix A2 to the LRA provide the applicant's UFSAR supplement for the Reactor Vessel Internals Inspection Program at St. Lucie Units 1 and 2, respectively. The program descriptions are consistent with the material contained in Section 3.1.4 of Appendix B and are, therefore, acceptable to the staff.

3.1.0.7.4 Conclusion

The staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the St. Lucie RVI components. In addition, the staff reviewed the Reactor Vessel Internals Inspection Program. The staff finds that this AMP will adequately manage cracking, loss of period, dimensional changes and reduction in fracture toughness of RVIs. In regards to this program, the applicant commits to submitting an integrated report for St. Lucie, Units 1 and 2, which will summarize the understanding of the aging effects applicable to the RVI and will contain a description of the St. Lucie Units 1 and 2 inspection plans, including methods for detection and sizing of cracks and acceptance criteria. On the basis of the information in the application, the staff concludes that the applicant has demonstrated that the aging effects associated with the RVIs will be adequately managed so that there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1 Reactor Coolant System Piping

3.1.1.1 Class 1 Reactor Coolant System Piping

The applicant described its AMR of the RCS Class 1 piping in LRA Section 3.1.1.1, "Class 1 Piping." The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the Class 1 piping will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.1.1 Summary of Technical Information in the Application

In Section 3.1.1.1 and Table 3.1-1 of the LRA, the applicant stated that the Class 1 RCS piping components are fabricated from either carbon steel, carbon steel with stainless steel cladding, low-alloy steel, stainless steel (including CASS), Inconel Alloys (Alloys 600 or 690), or nickel-based alloy weld materials. In Table 3.1-1 of the LRA, the applicant stated that the Class 1 RCS piping components are exposed internally to the primary treated water environment and externally to either the containment atmosphere or postulated leaks of the primary treated water. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-2 of the LRA, respectively.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive Class 1 RCS piping components that are within the scope of license renewal.

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.1.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS Class I piping and associated pressure boundary components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This also included the plant-specific operating experience at both subject plants.

Aging Management Programs. In Table 3.1-1 of the LRA, the applicant identified that the following AMPs or activities will be used to manage the aging effects that are applicable to the Class 1 RCS piping components during the periods of extended operation, as required by 10 CFR 54.21(a)(3).

- Chemistry Control Program

- ASME Section XI, Subsections IWB, IWC, and IWD ISI Program

- Boric Acid Wastage Surveillance Program

- Alloy 600 Inspection Program

- Thermal Aging Embrittlement of CASS Program
- Small Bore Class 1 Piping Inspection

3.1.1.1.2. Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RCS Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require AMRs, identifies the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive Class 1 RCS piping components within the scope of license renewal.

- cracking in components that are fabricated from stainless steel, carbon steel with internal stainless steel clad surfaces, Alloy 600 or 690, or nickel-based alloy weld materials, and are exposed internally to treated primary water environments
- cracking and reduction in fracture toughness in CASS components that are exposed internally to treated primary water environments
- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)
- loss of material in carbon steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant's TLAA for the components is addressed in LRA Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components." The staff's evaluation of the TLAA is given in Section 4.3 of this SER.

Aging of Class 1 RCS Piping Components Exposed to Internal Environments. The Class 1 RCS Piping for St. Lucie does not include any carbon steel piping components whose carbon steel portions of the components are in direct internal contact with the treated (borated) primary coolant. All Class 1 RCS piping components that are fabricated from carbon steel are clad on their inside surfaces with austenitic stainless steel; and it is the austenitic stainless steel cladding that is in direct contact with the treated primary coolant. Loss of material and cracking are therefore not considered to be issues for the carbon steel portions of these components under internal liquid environments.

Section 3.1 of the SRP-LR (NUREG-1800) does not identify that loss of material due to erosion or general corrosion is an issue for austenitic stainless steels (including CASS) or Inconel materials (e.g., nickel-based alloys such as Alloy 600 or Alloy 690 base metal materials or Alloy 82/182 or 52/152 filler metal materials) in PWR environments because the materials are inherently resistant to general corrosion; however, loss of material may be an applicable effect for these components under wet conditions, if the components have creviced areas that may be exposed to the fluids with high concentrations of halogens, sulfates, or oxygen. The applicant has not indicated in Section 3.1 of the application that the Class 1 piping components fabricated from austenitic stainless steel or Inconel materials are subject to vibrational levels that could subject the components to wear or have creviced regions that could subject the components to crevice or pitting corrosion. The applicant has therefore not identified loss of material as an applicable effect for the surfaces of components that are fabricated from stainless steel, carbon steel with stainless steel cladding, or Alloy 600/690 or other nickel-based alloy weld materials and that are exposed to treated primary water environments. The applicant's basis for concluding that loss of material by wear or by pitting/crevice corrosion is not an applicable effect for the austenitic stainless steel or Inconel Class 1 piping components is sufficiently summarized in Section 5.1 of the LRA. In this section, the applicant indicates that austenitic stainless steel (including CASS) and Inconel materials are not susceptible to general or pitting/crevice corrosion if the halogens, sulfates, and oxygen concentrations for the RCS are reduced below 150 ppb, 100 ppb, and 100 ppb, respectively. These concentrations are consistent with the recommended concentrations for the RCS coolant in the EPRI PWR Primary Water Chemistry Guidelines. The applicant uses the Chemistry Program—Water Chemistry Subprogram to reduce the halogen and oxygen concentrations in the RCS coolant below these levels. The staff evaluated this AMP in Section 3.0.5.6 of this SER.

Loss of material may also be an applicable effect in RCS components if the components are subject to wear. The austenitic stainless steel and Inconel materials in the RCS (including those in the Class 1 piping system) are also designed to be resistant to abrasive and erosive wear mechanisms. The staff therefore does not consider the austenitic stainless steel and Inconel Class 1 piping components to be susceptible to loss of material by wear.

Section 3.1 of the SRP-LR does not indicate that loss of material by general corrosion, pitting/crevice corrosion, or wear are applicable aging effects for Class 1 piping components fabricated from austenitic stainless steel or Inconel. The applicant's assessment of loss of material mechanisms for Class 1 piping components fabricated from austenitic stainless steels or Inconel is consistent with the staff's technical assessments discussed in the previous two paragraphs and with the staff's assessment in Section 3.1 of the SRP-LR, and therefore is acceptable to the staff.

According to Section 3.1 of the SRP-LR, RCS piping made from austenitic metals, including austenitic stainless steel, and Inconel alloys (including Alloy 600 and Alloy 690 base metals and nickel-based alloy weld metals) are known to be susceptible to SCC if the materials are exposed to the primary treated coolant (i.e., if the materials are known to be susceptible to PWSCC) or if the internal surfaces of the pipe or component are in contact with oxygenated liquids or liquids with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. The applicant has identified in Table 3.1-1 of the application that cracking is an applicable effect for the surfaces of Class 1 stainless steel components, stainless steel cladding of clad carbon steel components, Alloy 600 and Alloy 690 base metal components, and nickel-based alloy welds that are exposed to treated primary water. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1) and is evaluated by the staff in Section 4.3.1 of this SER.

Irradiation embrittlement is not a concern for the RCS Class 1 piping and associated components because the expected neutron fluence is much less than the threshold level at which changes in properties of the material would occur. However, according to the staff's ISG on CASS, CASS components may be susceptible to loss of fracture toughness as a result of thermal aging if certain metallurgical factors exist.[3] Thermal aging (thermal embrittlement) refers to the gradual and progressive changes in the micro structure and properties of a material due to extended exposure to elevated temperatures. The applicant has identified that reduction in fracture toughness is an additional aging effect for the Class 1 piping and valve components that are fabricated from CASS[4] and are exposed to treated primary water. This assessment is consistent with the staff's corresponding assessment in Section 3.1 of the SRP-LR and is acceptable to the staff. The applicant proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking and loss of fracture toughness in all Class 1 piping components fabricated from CASS materials. The applicant also credited the CASS Program with managing loss of fracture toughness in the Class 1 piping, fitting, and safe-end components that are fabricated from CASS. In its review of the St. Lucie LRA, the staff determined that the applicant has adopted the guidelines in the staff's ISG (refer to footnote 1 below) on aging of Class 1 CASS components as the basis for determining whether the CASS Program needs to be credited as an additional program for managing this aging effect. These guidelines provide an acceptable basis for excluding the CASS Class 1 valve bodies from the scope of the Thermal Aging Embrittlement of CASS Program. The staff's evaluation of the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program is given in Section 3.0.5.3 of this SER. The staff's evaluation of the Thermal Aging Embrittlement of CASS Program is given in Section 3.1.0.2 of this SER. The applicant addresses the effect that reduction in fracture toughness will have on the leak-before-break analysis for the RCS main loop piping in Section 4.6.1 of the application. The staff evaluates this TLAA in Section 4.6.1 of the SER.

Aging of Class 1 RCS Piping Components Exposed to External Environments. The applicant has identified that loss of material due to boric-acid-induced corrosion resulting from leakage of borated water onto the external surfaces of Class 1 RCS components made from carbon or low-alloy steel (including bolted connections and integral attachments and supports) is a potential aging effect requiring aging management. This is consistent with the staff's corresponding assessment in Section 3.1 of the SRP-LR and is acceptable to the staff. The applicant's identification of aging effects for the low-alloy steel bolting materials is discussed in

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3 Letter from C.I. Grimes (NRC) to D.J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,"* Project No. 690, dated May 2000. The guidance in this document defines the metallurgical conditions and fabrication factors that can induce thermal aging in CASS materials.

4 The other aging effect is cracking, which was assessed by the staff in the previous paragraph.

more detail in the following paragraph.

The Class 1 RCS bolting is made out of low-alloy steel (ferritic fasteners). These fasteners are stressed (preloaded) to ensure the integrity of the pressure boundary in Class 1 RCS bolted connections. The applicant has identified three potential mechanisms that can occur which may result in a loss of mechanical closure integrity for these materials, including (1) stress relaxation, (2) aggressive chemical attack from leaks of borated primary coolant (treated primary water), and (3) SCC of high strength bolting materials. The first mechanism is a phenomenon in which the preloaded stress applied to the bolts for structural integrity loosens up over time. This phenomenon is known as stress relaxation. The second mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is aggressive attack or corrosion as a result of exposure to potential leaks of the treated (borated) primary coolant. Industry experience and NRC generic communications have demonstrated that ferritic (carbon steel and low-alloy steel) steel materials may be extremely susceptible to loss of material/aggressive corrosive attack when exposed to borated water. The bolts also may be susceptible to SCC, particularly if the yield strengths for the bolting materials are greater than 150 kilograms per square inch (ksi). Therefore, the third mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is SCC. Consistent with Section 3.1.1 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low-alloy steel bolting materials also covers these three aging effects. These aging effects are consistent with the aging effects identified Section 3.1 of the SRP-LR for low-alloy steel bolting materials and are therefore acceptable to the staff.

The applicant did not identify any aging effects as being applicable to RCS piping exposed to the containment air atmosphere. The applicant defines containment air as having a maximum temperature of 120 °F and an average humidity of 73 percent. Carbon steel components that are exposed to moist (wet) air environments may be subject to general corrosion, pitting corrosion, crevice corrosion, or MIC. Loss of material may be a concern for carbon steel components that are exposed to wetted air environments. During normal operations of the St. Lucie reactor units, the external surfaces of RCS piping components will be hotter than the ambient conditions within the containment. During periods of plant shutdowns, the humidity of the containment atmosphere is controlled by use of air conditioning units inside the containment structure.[5] Since precipitation will not occur under these operating conditions, the staff does not consider loss of material to be a concern for the surfaces of Class 1 carbon steel piping that are exposed to the containment air atmosphere at St. Lucie.

<u>Aging Management Programs</u>. The applicant indicated that the following existing and new programs will be used to manage the aging effects that are applicable to the Class 1 RCS piping components for the extended periods of operation at the St. Lucie reactor units.

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD

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5 In Table 3.0-2 of the St. Lucie application, the applicant provides the key parameters (temperature, relative humidity, etc.) for indoor and outdoor atmospheric environments at the plants. In footnote 2 of the table, the applicant clarifies that it uses the generic term "indoor air - not-air-conditioned" for external containment air or indoor air environments that create condensation or wetted conditions on the surfaces of the components. The applicant's AMRs for the Class 1 piping do not indicate that any of the Class 1 piping components are exposed externally to "indoor air - not-air-conditioned (-wetted)" environments. Therefore, the staff do not consider loss of material due to general corrosion to be a concern for these components.

Inservice Inspection Program to manage cracking in components that are fabricated from stainless steel (including CASS), carbon steel with internal stainless steel cladding, and Inconel alloys (i.e., Alloy 600/690 or nickel-based alloy weld materials), and that are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program to manage loss of mechanical closure integrity in low-alloy steel bolts that are exposed to containment air or could be exposed externally to leaks of the primary treated water (the applicant's combined use of the programs will account for loss of mechanical integrity that could be induced either by loss of material due to excessive chemical/corrosive attack, or loss of preload in the bolts)

- the Boric Acid Wastage Surveillance Program to manage loss of material in carbon steel piping, fittings, and nozzles that could be exposed externally to leaks of the primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in Class 1 Alloy 600 instrument nozzles, fittings, and thermowells and nickel-based alloy weld materials that are exposed internally to primary treated water

- the Thermal Aging Embrittlement of CASS Program to manage reduction in fracture toughness in Class 1 RCS components that are made from CASS and are exposed internally to primary treated water

- the Small Bore Class 1 Piping Inspection as an additional program to manage cracking in small bore (less than 4 inches in diameter) Class 1 piping, fittings, and safe-ends that are fabricated from stainless steel and are exposed internally to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the Class 1 piping and associated components and serves as a mitigative means of minimizing cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects that are applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive Class 1 RCS piping components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, pumps, or valves and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed externally to leaks of primary treated water. This program is consistent with the applicant's surveillance program that is in effect in response to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluated this program in Section 3.0.5.4 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all Class 1 RCS components that are made from Alloy 600 base metals or nickel-based alloy weld metals and are susceptible to PWSCC. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Thermal Aging Embrittlement of CASS Program (Section 3.1.6 of Appendix B to the LRA) manages loss of fracture toughness in RCS piping and nozzles (including safe-ends) fabricated from CASS. The staff's evaluation of this AMP is described in Section 3.1.0.2 of this SER.

The Small Bore Class 1 Piping Inspection (Section 3.1.5 of Appendix B to the LRA) manages age-related cracking in small bore Class 1 RCS piping less than 4 inches nominal pipe size. The staff's evaluation of this AMP is described Section 3.1.0.3 of this SER.

3.1.1.1.3 Conclusions

The staff has reviewed the information in Section 3.1.1.1 of the LRA, Table 3.1-1 of the LRA, and the applicant's response to RAI B.3.1.5, dated September 26, 2002, as the information relates to the applicant's AMRs for the St. Lucie Class 1 RCS piping components. On the basis of this review, the staff concludes that the applicant has demonstrated that aging effects associated with the Class 1 piping components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2 RCS Non-Class 1 Piping

The applicant describes its AMR of the RCS non-Class 1 piping in Section 3.1.1.2, "Non-Class 1 Piping," and Table 3.1-1 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the non-Class 1 piping will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2.1 Summary of Technical Information in the Application

In Section 3.1.1.2 and Table 3.1-1 of the LRA, the applicant identified that the non-Class 1 RCS piping components consist of valves, piping and fittings, thermowells, tubing and fittings, orifices, and bolting. These components are fabricated from either carbon steel or stainless steel (including CASS) materials. In Table 3.1-1 of the LRA, the applicant identified that the non-Class 1 RCS piping components are exposed internally to the primary treated water environment and externally to either the containment atmosphere or postulated leaks of the primary treated water. The applicant defined these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA, respectively.

<u>Aging Effects</u>. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive Class 1 RCS piping components that are within the scope of license renewal.

- cracking
- reduction in fracture toughness
- loss of mechanical closure integrity

In accordance with Section 3.1.1.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS piping and associated pressure boundary components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for non-Class 1 RCS piping components at St. Lucie. This review also included the plant-specific operating experience at both subject plants.

Aging Management Programs. In Table 3.1-1 of the LRA, the applicant identified the following AMPs or activities to be used to manage the aging effects that are applicable for the non-Class 1 RCS piping components during the periods of extended operation.

- ASME Section XI, Subsections IWB, IWC, and IWD ISI, program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program

3.1.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the non-Class 1 RCS piping and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Table 3.1-1 of the LRA lists the non-Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require AMRs, identifies the aging effects that require management for these components, and identifies the AMRs that will be used to manage these effects.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive non-Class 1 RCS piping components within the scope of license renewal:

- cracking in components that are fabricated from stainless steel and are exposed internally to treated primary water environments

- cracking and reduction in fracture toughness in CASS components that are exposed internally to treated primary water environments

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant addresses thermal fatigue of non-Class 1 piping components in LRA Section 4.3.2, "ASME

Boiler and Pressure Vessel Code, Section III, Class 2 and 3, and ANSI B31.1 Components." The staff's evaluation of the applicant's TLAA for non-Class 1 piping components is given in Section 4.3.2 of this SER.

Aging of Non-Class 1 RCS Piping Components Exposed to Internal Environments. The applicant's identification of the aging effects applicable to the non-Class 1 RCS piping components that are exposed to the primary treated water environment is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same internal environment. This includes the applicant's identification of aging effects for non-Class 1 valves fabricated from CASS. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the non-Class 1 RCS piping components that are exposed to the primary treated water environment is consistent with the staff's corresponding analysis for these materials in the GALL Report, Section IV.C2, and is therefore acceptable to the staff.

Aging of Non-Class 1 RCS Piping Components Exposed to External Environments. The applicant's identification of the aging effects applicable to the non-Class 1 RCS piping components that are exposed to the containment air or postulated leaks of primary treated water is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same external environments. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. The applicant did not indicate in Chapter 3.1.1.2 of the LRA that the non-Class 1 piping components fabricated from austenitic stainless steel are subject to abrasive or erosive mechanisms that could cause the components to wear or have creviced regions that could lead to crevice or pitting corrosion. The applicant therefore did not identify loss of material as an applicable effect for the surfaces of non-Class 1 piping and valve components that are fabricated from stainless steel (including CASS). The applicant's basis for concluding that loss of material by wear or by pitting/crevice corrosion is not an applicable effect for the austenitic stainless steel or Inconel Class 1 piping components is sufficiently summarized in Appendix C, Section 5.1, of the LRA. The staff's evaluation of the topic of loss of material in the non-Class 1 piping components is identical to the staff's assessment regarding the applicability of loss of material mechanisms to Class 1 austenitic stainless steel piping components, which is given in Section 3.1.0.2 of this SER.

Section 3.1 of the SRP-LR does not indicate that loss of material by general corrosion, pitting/crevice corrosion, or wear is an applicable aging effect for RCS piping components fabricated from austenitic stainless steels. The applicant's assessment of loss of material mechanisms for Class 1 piping components fabricated from austenitic stainless steel is consistent with the staff's technical assessment discussed in Section 3.1.1.1.2 of this SER and with the staff's assessment in Section 3.1 of the SRP-LR and therefore is acceptable to the staff.

For bolting materials, loss of mechanical closure integrity covers loss of closure integrity due to stress relaxation, and wear, and for carbon steel bolts and low-alloy steel bolts, due to aggressive corrosive attack if the bolts are exposed to reactor coolant leaks. Industry experience has demonstrated that stainless steel bolting is not susceptible to aggressive corrosive attack in the same manner as carbon steel or low-alloy steel bolting. It should be noted that in the original AMRs for the non-Class 1 RCS bolting, the applicant identified that the non-Class 1 RCS bolting is made either from stainless steel or from carbon steel. The applicant has appropriately identified that loss of mechanical closure integrity due to aggressive attack is an applicable effect for the carbon steel non-Class 1 bolting in the same manner it identified that the aging effect was applicable to the RCS Class 1 bolting fabricated from low-alloy steel. However, the applicant did not identify that loss of mechanical closure integrity is an applicable aging effect for the stainless steel or carbon steel non-Class 1 bolting materials as a result of stress relaxation. In Open Item 3.1.1.2-1, the staff informed the applicant that it needed to justify why it does not consider loss of material resulting from stress relaxation to be an applicable effect for the stainless steel and carbon steel non-Class 1 bolting materials. The staff stated that if this aging effect is applicable to the stainless steel and carbon steel non-Class 1 bolting materials, the aging effect would need to be added to the AMRs for these bolting materials and an applicable inspection-based AMP would need to be proposed to manage the aging effect.

In its response to Open Item 3.1.1.2-1, dated March 28, 2003, the applicant clarified that the threshold for stress relaxation of bolted connections is a temperature dependent phenomenon. The applicant stated that the process for identifying aging effects associated with the St. Lucie bolting materials is given in Appendix C of the application. The applicant stated that the review process for bolted connections is based upon industry guidance developed by the Babcock and Wilcox (B&W) Owners Group, which was tailored to address the St. Lucie bolting materials and environments and St. Lucie plant-specific operating experience. The applicant stated that, according to ASME Section III, stress relaxation may occur at temperatures of 700 °F or higher for Grade B7 bolting materials complying with ASME/ASTM Standard Procedure SA/A-193, and at temperatures of 500 °F or higher for Grade B23 or B24 bolting materials complying with ASME/ASTM Standard Procedure SA/A-540. In its response to Open Item 3.1.1.2-1, the applicant also clarified that stress relaxation was identified in LRA Table 3.1-1 as an applicable aging effect mechanism for Class 1 RCS bolting because some of the bolting was manufactured with SA/A-540, Grade B23 or B24 materials, which could be exposed to operating temperatures in excess of 500 °F. In its response to Open Item 3.1.1.2-1, the applicant also stated that the bolting materials used for non-Class 1 bolted connections are Grade B7 materials that conform to ASME/ASTM Standard SA/A-193. The applicant stated that since the threshold for stress relaxation in SA/A-193 Grade B7 bolting materials is in excess of 700 °F, and because the operating temperature for the RCS is well below this threshold, stress relaxation was not identified as an applicable aging effect mechanism for the bolts in non-Class 1 RCS bolted connections.

The staff reviewed the operating thresholds and footnotes for stress relaxation in Section II of the ASME Boiler and Pressure Vessel Code for these bolting materials and confirmed that the applicant's determination was valid. The staff concludes that the applicant's response to Open Item 3.1.1.2-1 provides an acceptable basis for omitting stress relaxation as an applicable aging effect mechanism for the non-Class 1 RCS bolting because the bolts will not be exposed to temperatures in excess of the threshold for stress relaxation in the bolting materials. The staff considers Open Item 3.1.1.2-1 to be resolved.

Based on its evaluation of these materials given in Section 3.1.1.1 of the SER, the staff concludes that the applicant's identification of aging effects for the non-Class 1 RCS piping components that are exposed to the containment air or postulated leaks of primary treated water is consistent with the staff's corresponding analysis for these materials in Section 3.1 of the SRP-LR and is therefore acceptable.

Aging Management Programs.

The applicant indicated that the following existing and new programs will be used to manage the aging effects that are applicable to the non-Class 1 RCS piping components within the extended periods of operation for the St. Lucie reactor units.

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in non-Class 1 RCS piping components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage reduction in fracture toughness in non-Class 1 RCS components that are made from CASS and are exposed to primary treated water

- the Boric Acid Wastage Surveillance Program to manage loss of material in carbon steel bolting that could be exposed to postulated leaks of the primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the non-Class 1 piping components and serves as a mitigative means of minimizing cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.6 of this SER.

The applicant has proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) to manage reduction in fracture toughness in non-Class 1 RCS valves fabricated from CASS.[6] The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects that are applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive non-Class 1 (Class 2 or 3) RCS piping components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, and pumps or valves, and loss of mechanical integrity in low-alloy steel/carbon steel bolting due to corrosion caused by exposure to primary treated water from the RCS. This program is consistent with the applicant's surveillance program that is in effect in response to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluated this program in Section 3.0.5.4 of this SER.

3.1.1.2.3 Conclusions

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6 The staff's basis for concluding that the Thermal Aging of CASS Program does not need to be credited as an additional AMP for managing loss of fracture toughness in RCS valves fabricated from CASS is given in Section 3.1.1.1.2 of this SER under the heading "Aging of Class 1 RCS Piping Components Exposed to External Environments."

The staff has reviewed the information in Section 3.1.1.2 and Table 3.1-1 of the LRA, as amended by the applicant's response to Open Item 3.1.1.2-1, and as the information relates to the applicant's AMRs for the St. Lucie non-Class 1 RCS piping components. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the non-Class 1 piping components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Pressurizer

The applicant describes its AMR of the RCS pressurizer in Section 3.1.2, "Pressurizer," and Table 3.1-1 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the pressurizer and its components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1 Summary of Technical Information in the Application

In Section 3.1.2 and Table 3.1-1 of the LRA, the applicant states that the pressurizer components consist of shells; upper heads; lower heads; spray, surge, relief valve, and safety valve nozzles and their associated safe-ends; instrumentation nozzles; heater sleeves manway covers; heater sheaths; and thermowells. These components are fabricated from either carbon steel with stainless steel inserts, stainless steel (including CASS), Inconel alloys (i.e., Alloy 600, Alloy 690, or nickel-plated Alloy 600), or low-alloy steel with either stainless steel or Alloy 82/182 cladding. In Table 3.1-1 of the LRA, the applicant states that the pressurizer components are exposed internally to the primary treated water environment and externally to either the containment atmosphere or concentrated boric acid resulting from leaks of the primary treated water. The applicant defines these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA, respectively.

3.1.2.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects are applicable to the passive pressurizer components that are within the scope of license renewal.

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.2 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the pressurizer components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern. This review also included the plant-specific operating experience at both units.

3.1.2.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following AMPs or activities to be used to manage the aging effects that are applicable to the pressurizer components during the periods of extended operation.

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD ISI Program
- Boric Acid Wastage Surveillance Program
- Alloy 600 Inspection Program
- Thermal Aging Embrittlement of CASS Program

3.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the pressurizer and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the pressurizer and associated components that are within the scope of the license renewal and require AMRs, identifies the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

3.1.2.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive pressurizer components within the scope of license renewal.

- cracking in components that are exposed internally to treated primary water environments and are fabricated from stainless steel, carbon steel with stainless steel inserts, Inconel alloys (i.e., Alloy 600/690, nickel-plated Alloy 600, or nickel-based weld materials), or low-alloy steel with stainless steel or Alloy 82/182 cladding
- cracking and reduction in fracture toughness in CASS components that are exposed internally to treated primary water environments
- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)
- loss of material in carbon steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The pressurizer components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant's TLAA for the components is addressed in LRA Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components." The staff's evaluation of the TLAA is given in Section 4.3 of this SER.

Aging of Pressurizer Components Exposed to Internal Environments. With the exception of the applicant's AMR for the pressurizer surge and spray nozzle thermal sleeves, the applicant's identification of the aging effects applicable to the pressurizer components that are exposed to the primary treated water environment is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same internal environment. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the pressurizer components that are exposed to the primary treated water environment is consistent with the staff's corresponding analysis for these materials in Section 3.1 of the SRP-LR, and is therefore acceptable.

By letter dated October 3, 2002, in response to RAI 2.3.1-2, the applicant included the pressurizer surge and spray nozzle thermal sleeves within the scope of license renewal and provided the following AMR for these components.

Component Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Aging Management Programs
Pressurizer Surge Nozzle Thermal Sleeves (IV.C2.5.5) Pressurizer Spray Nozzle Thermal Sleeves (IV.C2.5.5)	Pressure Boundary[a]	Alloy 600	Treated Water – Primary	None	None Required

a. Although the pressurizer surge and spray nozzle thermal sleeves are not part of the pressure boundary, they do serve the function of protecting the pressurizer surge and spray nozzles (which are pressure boundary components) against thermal shock and thermal cycling.

In its RAI response dated October 3, 2002, the applicant concluded that there are no applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves because the applied loads on the thermal sleeves are low. Section 5.1 of the application provides an acceptable basis for concluding that loss of material due to wear and/or crevice corrosion is not an applicable effect for the Alloy 600 components in the RCS. However, the pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 materials. Industry experience has demonstrated that these materials and their associated weld metals (i.e., Alloy 82/182) are susceptible to PWSCC. Therefore, contrary to the applicant's assessment, the staff concluded that the pressurizer surge and spray nozzle thermal sleeves may be susceptible to cracking as a result of PWSCC.

The staff issued Open Item 3.1.2.2-1 to address whether PWSCC needed to be identified as an applicable aging effect for the pressurizer surge and spray nozzle thermal sleeves that were brought within the scope of license renewal by the applicant. In its response to Open Item 3.1.2.2-1, dated March 28, 2003, the applicant clarified that the pressurizer surge and spray nozzle thermal sleeves are not part of the reactor coolant pressure boundary. However, the thermal sleeves serve the function of protecting the pressurizer surge and spray nozzles against thermal shock and thermal cycling. The pressurizer spray nozzle thermal sleeves are fabricated from Alloy 600 forgings and the pressurizer surge nozzle thermal sleeves are fabricated from rolled Alloy 600 plates that include a longitudinal Alloy 82/182 seam weld. As discussed in Section 3.1.0.1 of this SER, industry experience has demonstrated that Alloy 600 base metal and Alloy 82/182 weld materials may be susceptible to PWSCC over time. The staff therefore concludes that PWSCC is an applicable aging effect for the pressurizer surge and spray nozzle thermal sleeves. However, neither of these sleeves are welded to the nozzles. Therefore, growth of a PWSCC-induced sleeve crack into the nozzles will not be of concern for the pressurizer surge or spray nozzles. Thus, based on the design of the thermal sleeves for the pressurizer surge and spray nozzles, the staff concludes that initiation of a PWSCC-induced crack (in the thermal sleeves) into the corresponding surge and spray nozzles is not an aging effect that needs to be managed during the extended periods of operation for the St. Lucie units.

The pressurizer surge nozzle thermal sleeves are manufactured with a seam weld. Through-wall growth of an postulated crack in the seam weld could occur from thermal shock or thermal cycling. Cracking of the pressurizer spray nozzle thermal sleeves is not expected since they are manufactured without a weld. By letter dated May 30, 2003, FPL provided supplemental information and a technical analysis of the effect of leakage through a thermal sleeve on the thermal fatigue analyses for the pressurizer surge lines and nozzles. Failure of a seam weld in the pressurizer surge line thermal sleeve could result in leakage past the thermal sleeve, thus impacting the fatigue usage in the surge line nozzle. In order to bound the potential impact of the leakage past the thermal sleeve, the applicant performed an analysis of the surge line nozzle with no thermal sleeve present. The applicant's analysis, without the thermal sleeve, demonstrated acceptable fatigue usage for the surge line nozzle.

The staff considered whether the fatigue analysis for the pressurizer surge nozzle thermal sleeves is bounding for the pressurizer spray nozzle thermal sleeves. In Section 4.3 of the LRA, the applicant demonstrates that the pressurizer surge nozzles are the limiting thermal fatigue locations for any pressurizer components within the scope of license renewal. Therefore, the applicant considers thermal fatigue analysis for the pressurizer surge nozzles to be bounding relative to any corresponding assessments that might be performed in an analysis of the pressurizer spray nozzles. The analysis described in the applicant's supplemental response dated May 30, 2003, assessed the effect that reactor coolant leakage through the thermal sleeves will have on the thermal stresses and cumulative usage factors (CUFs) for the pressurizer surge nozzles. On the basis of the results of this analysis, the staff agrees with the applicant that the leakage analysis for the pressurizer surge nozzle thermal sleeves and resulting thermal fatigue analysis for the pressurizer surge nozzles is bounding for any corresponding analyses that would be performed on the pressurizer spray nozzles and their thermal sleeves. The following technical arguments provide the bases for this conclusion:

- Residual stress levels in the seam welds of the pressurizer surge nozzle thermal sleeves would make the pressurizer surge nozzle thermal sleeves a more likely source of cracking than the would the corresponding loadings on the forgings used to fabricate the pressure spray nozzle thermal sleeves.

- The pressurizer surge nozzles are the limiting thermal fatigue locations for the pressurizer components within the scope of license renewal (i.e., they have the highest cumulative usage factors of any pressurizer components within the scope of license renewal).

By letter dated June 24, 2003, the applicant submitted the following additional information in order to support its basis that circumferential cracking of a thermal sleeve is not an aging effect requiring aging management:

> Circumferential cracking of Alloy 600 components has occurred in the industry; however, based upon design/fabrication differences, circumferential cracking of the pressurizer nozzle thermal sleeves is not considered a credible aging effect requiring management. Unlike Alloy 600 nozzles which have experienced circumferential cracking and are welded to reactor pressure boundary components around the circumference of the nozzle, the pressurizer nozzle thermal sleeves do not have a circumferential weld, and are not pressure boundary components.
>
> For typical Alloy 600 nozzles, the presence of circumferential cracking is due mainly to the high axial stresses from the weld attaching the nozzle to the hole in the pressure boundary component. The weld shrinkage produces both membrane and bending stresses in the axial direction of the nozzle. Since the nozzles are pressure boundary components, there may also be axial stresses in the nozzles due to pressure. Finally, there may be small bending loads on these nozzles that can result in additional axial stresses. Note that since the thermal sleeves do not have a circumferential weld or a bending load to provide axial stresses, there is no significant driving function for circumferential cracking to occur. Therefore, through wall circumferential cracking of the thermal sleeves is not considered a credible aging effect.
>
> As described in the response to SER Open Item 3.1.2.2-1, the St. Lucie pressurizer surge nozzle thermal sleeves are fabricated from rolled plate material with a longitudinal seam weld, and the pressurizer spray nozzle thermal sleeves are fabricated from seamless pipe. The sleeves are then inserted into the nozzles and locally expanded in a grooved area in the ID of the nozzles. There are no welds attaching the thermal sleeves to any pressure boundary materials. Since the sleeves do not perform a pressure boundary or structural function, they are not exposed to any significant operating stresses other than those related to manufacturing residual stresses (i.e., principally those hoop stresses tending to spring open the sleeve at the longitudinal weld seam). The axial residual stresses due to forming (due to Poisson's ratio effects) are expected to be sufficiently lower than those in the circumferential direction such that any potential PWSCC cracking would occur in the axial direction of the thermal sleeve.
>
> There may be some residual axial bending stresses at the region where the thermal sleeve is expanded into the groove in the nozzle. In the highly unlikely event that a complete circumferential crack occurred in this region, it is not expected that the thermal sleeve would move. Any cracking in the groove region itself would still result in the thermal sleeve remaining captured. The lower portion of the surge nozzle thermal sleeve cannot move downward since it is captured in the nozzle (i.e., the nozzle ID is smaller than the thermal sleeve OD). If the cracking was immediately above the groove, the upper portion would not be expected to move upward since only fluid friction loads are available to move the thermal sleeve upward, and these are significantly less than gravity loads that will keep the thermal sleeve in place within the nozzle. Additionally, it is noted that the surge screen assembly within the pressurizer vessel would preclude any part from entering the pressurizer. Likewise, the lower portion of the spray nozzle thermal sleeve is captured by the spray head assembly, and if cracking were to occur above the groove both gravity and fluid

flow would act to prevent the sleeve from entering the spray piping.

In conclusion, based upon the above, circumferential cracking of the thermal sleeves is not an aging effect requiring management.

The applicant's supplemental RAI response provides an acceptable basis for concluding that any postulated cracking of a pressurizer surge or spray nozzle thermal sleeve is likely to be oriented in the axial orientation because the circumferential stresses, which could potentially lead to the initiation of an axially oriented crack, are limiting relative to any axially oriented stresses that could potentially lead to the initiation of an circumferentially oriented crack. The applicant's information also provides an acceptable technical basis for concluding that while circumferential cracking is not likely, complete cracking of a thermal sleeve would not result in the generation of a loose part internal to the St. Lucie pressurizer shells. Based on this assessment and the leakage-thermal fatigue analysis discussed earlier in this section, the staff concurs that neither axial cracking nor circumferential cracking requires aging management for pressurizer surge and spray nozzle thermal sleeves.

On the basis of this additional information, the staff concludes that the applicant's response to Open Item 3.1.2.2-1, as modified by the supplemental responses dated May 30, 2003, and June 24, 2003, provides an acceptable basis for concluding that cracking induced by stress corrosion or thermal fatigue in either a pressurizer surge nozzle thermal sleeve plate or weld or a pressurizer spray nozzle thermal sleeve forging is not an aging effect that needs to be managed during the periods of extended operation for the St. Lucie units. The staff considers Open Item 3.1.2.2-1 closed. The staff's assessment of the thermal fatigue analysis for the pressurizer components within the scope of license renewal is given in Section 4.3 of this SER.

Aging of Pressurizer Components Exposed to External Environments. The applicant's identification of the aging effects that are applicable to the pressurizer components that are exposed to the containment air or postulated leaks of the primary treated water (i.e., postulated borated water leakage) is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same external environment. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the pressurizer components that are exposed to the containment air or postulated leaks of primary treated water is consistent with the staff's corresponding analysis for these materials in Section 3.1 of the SRP-LR and is therefore acceptable to the staff.

3.1.2.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the pressurizer components within the extended periods of operation for the St. Lucie, Units 1 and 2:

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in components that are exposed internally to primary treated water and are fabricated from stainless steel (including CASS), carbon steel with stainless steel inserts, Inconel alloys (i.e., Alloy 600/690 or nickel-plated Alloy 600) or low-alloy steel with Alloy 82/182 or stainless steel cladding

- the Chemistry Control Program to manage cracking in the carbon steel manway covers that are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program to manage loss of mechanical integrity in low-alloy steel bolts that are exposed to containment air or could be exposed to postulated leaks of primary treated water (the applicant's combined use of the programs will account for loss of mechanical integrity that could be induced by either SCC, loss of material due to excessive chemical/corrosive attack, or loss of preload in the bolts)

- the Boric Acid Wastage Surveillance Program to manage loss of material in carbon steel manway covers that could be exposed to postulated leaks of primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in pressurizer components that are made from Inconel materials (i.e., Alloy600/690 or nickel-plated Alloy 600) and are exposed to primary treated water.

- the Thermal Aging Embrittlement of CASS Program to manage reduction in fracture toughness in Class 1 RCS components that are made from CASS and are exposed to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the pressurizer components and serve as a mitigative means of minimizing loss of material and cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive pressurizer components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, and pumps or valves, and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed to postulated leakage of primary treated water from the RCS. This program is consistent with the applicant's surveillance program that is in effect in response to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluated this program in Section 3.0.5.4 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all pressurizer components that are made from Alloy 600/690 base metals or nickel-based weld metals and are susceptible to PWSCC. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Thermal Aging Embrittlement of CASS Program (Section 3.1.6 of Appendix B to the LRA) manages loss of fracture in RCS piping, nozzles (including safe-ends), pump and valve components, and RVI components fabricated from CASS. The staff's evaluation of this AMP is described in Section 3.1.0.2 of this SER.

3.1.2.3 Conclusions

The staff has reviewed the information in Section 3.1.2 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the St. Lucie pressurizer components and as amended by the information provided in the applicant's response to RAI 2.3.1-2, dated October 3, 2002, and Open Item 3.1.2.2-1, dated March 28, 2003. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the pressurizer will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Reactor Vessels

In Section 3.1.3, "Reactor Vessels," of the LRA, the applicant describes its AMR of the RVs. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the RV components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.1 Summary of Technical Information in the Application

In Section 3.1.3 and Table 3.1-1 of the LRA, the applicant identifies that the RV components are fabricated from stainless steel, Alloy 600, low-alloy steel, low-alloy steel with stainless steel cladding, carbon steel, and carbon steel with stainless steel cladding. In Table 3.1-1 of the LRA, the applicant identified that the RV components are exposed internally to primary treated water and externally to containment air and borated water leaks. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-2 of the LRA, respectively.

3.1.3.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable for the passive RV components that are within the scope of license renewal.

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.3 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.3.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified that the following AMPs or activities will be used to manage the aging effects applicable for the RV components during the periods of extended operation:

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Alloy 600 Inspection Program
- Reactor Vessel Integrity Program
- Boric Acid Wastage Surveillance Program

3.1.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.3, Table 3.1-1, and pertinent sections of Appendices A and B of the LRA, regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RV and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 5.21(a)(3).

Table 3.1-1 of the LRA lists the RV components that are within the scope of license renewal and require AMRs, details the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

3.1.3.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive RV components within the scope of license renewal.

- cracking in components that are fabricated from stainless steel, carbon steel with internal stainless steel clad surfaces, low-alloy steel with internal stainless steel clad surfaces, and Alloy 600, and that are exposed internally to treated primary water environments

- reduction in fracture toughness in low-alloy steel with stainless steel cladding that is exposed internally to treated primary water environments

- loss of material due to mechanical wear in Alloy 600 components (core stabilizing lugs) that are exposed internally to primary treated water environments

- loss of material in carbon steel and low-alloy steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of mechanical closure integrity in low-alloy steel components (closure studs, nuts, and washers) that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of material due to mechanical wear in low-alloy steel components that are exposed externally to containment air

Fatigue. The potential for cracking to occur in carbon or low-alloy steel RV materials is predominantly a phenomenon of thermal fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Section 4.3.1 of the LRA. The staff's evaluation of the TLAA is given in Section 4.3 of this SER.

Aging of Reactor Vessel Components Exposed to Internal Environments. The RV components for St. Lucie do not include any carbon steel components in direct internal contact with the treated (borated) primary coolant. All RV components that are fabricated from carbon steel are clad on their inside surfaces with austenitic stainless steel, and it is the austenitic stainless steel cladding that is in direct contact with the treated primary coolant. Loss of material and cracking are therefore not considered to be issues for the carbon steel portions of these components under internal liquid environments.

According to Section 3.1 of the SRP-LR, loss of material due to erosion or general corrosion is not normally an issue for austenitic stainless steel or Inconel materials (e.g., Alloy 600 base metal materials) in PWR environments because the materials are inherently resistant to erosion and general corrosion. The staff compared the applicant's AMRs for Inconel and austenitic stainless steel RV components to corresponding AMRs in Section 3.1 of the SRP-LR. These AMRs were found to be consistent with Section 3.1 of the SRP-LR, and therefore acceptable to the staff.

The applicant indicated in Section 3.1 of the application that the core support lugs fabricated from Inconel material are subject to vibrational levels that could cause the components to wear. The applicant has therefore identified loss of material as an applicable effect for the core support lugs fabricated from Alloy 600. Loss of material of the core support lugs is an aging effect that is consistent with the staff's position on previous LRA (e.g., Turkey Point) and therefore acceptable to the staff.

Austenitic stainless steel and Inconel alloys are susceptible to SCC under certain conditions in the PWR water environment. The applicant has identified in Table 3.1-1 of the LRA that cracking is an applicable effect for the surfaces of RV stainless steel components, stainless steel cladding of clad carbon steel components, and Alloy 600 base metal components that are exposed to treated primary water. These components include the control element drive mechanisms, the incore instrumentation nozzle tube, and the core stabilizing and stop lugs. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1) and is evaluated by the staff in Section 4.3.1 of this SER.

Reduction in fracture toughness is also of concern during the period of extended operation for the RV intermediate and lower shells. The alloy steel weld and base metals in the RV beltline are subject to reduction in fracture toughness as a result of neutron embrittlement. The applicant has identified reduction in fracture toughness as an applicable effect for the RV beltline base metal and weld materials. The applicant addresses reduction of fracture toughness of the RV beltline materials in the TLAA for the RV materials, as given in Section 4.3 of the application. The staff's evaluation of the TLAA for the RV beltline materials is provided in Section 4.3 of this SER.

Reduction in fracture toughness may also occur in certain types of CASS components as a result of prolonged exposure to service temperatures above 250 °C (482 °F) (i.e., as a result of thermal aging). The applicant, however, did not identify any RV components that are fabricated from CASS.

Aging of Reactor Vessel Components Exposed to External Environments. Loss of material may occur in the RV components under certain conditions. Carbon steel and low-alloy steel components may be susceptible to general-corrosion-induced loss of material under wet or damp conditions. Industry experience also demonstrates that borated water leakage from the RCS may corrode carbon or low-alloy steel RCS pressure boundary components. NUREG/CR-5576 provides a summary of boric acid wastage events that have occurred in primary alloy or carbon steel pressure boundary components of domestic PWRs through 1990. The applicant has identified that loss of material is an applicable effect for the exterior surfaces of carbon or low-alloy steel RV components that could be subjected to potential borated water leakage. Therefore, the carbon or low-alloy steel RV components that may be susceptible to loss of material include (1) RV steel shells, flanges, rings, bottom heads, closure head domes, and primary inlet/outlet nozzles, (2) high strength alloy steel bolting materials, and (3) alloy steel integral attachments (nozzle supports and safe-ends). This is consistent with the staff's assessment in Section 3.1 of the SRP-LR and is therefore acceptable.

The RV bolting is made out of low-alloy steel (ferritic fasteners). These fasteners are stressed (preloaded) to ensure the integrity of the pressure boundary in RV bolted connections. The applicant has identified three potential mechanisms that can occur which may result in a loss of mechanical closure integrity for these materials including (1) stress relaxation, (2) aggressive chemical attack from leaks of borated primary coolant, and (3) SCC of high strength bolting materials. The first mechanism is a phenomenon in which the preloaded stress applied to the bolts for structural integrity loosens up over time. This phenomenon is known as stress relaxation. The second mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is corrosion as a result of being exposed to potential leaks of the treated (borated) primary coolant, as discussed in the preceding paragraph. Industry experience and NRC generic communications have demonstrated that ferritic (carbon steel and low-alloy steel) steel materials may be susceptible to aggressive corrosive attack when exposed to borated water. The third mechanism that can lead to loss of mechanical closure integrity is SCC, particularly if the yield strengths for the bolting materials are greater than 150 ksi. Consistent with Section 3.1.1 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low-alloy steel bolting materials also covers these three aging effects. These aging effects are consistent with the aging effects identified in Section 3.1 of the SRP-LR for low-alloy steel bolting materials and are therefore acceptable to the staff.

The applicant identified loss of material as being an applicable aging effect for the RV closure studs, nuts, washers, and vessel flanges exposed to containment air atmosphere. Loss of material requiring aging management for RV closure components exposed to the containment air atmosphere is due to mechanical wear. During plant operation, the surface temperatures of these components exceeds 212 °F; moisture is not present and components are not subject to general corrosion. Loss of material, therefore, is considered by the staff to be a concern for the external surfaces of the subject RV components in containment air atmospheres for St. Lucie. This is consistent with the aging effects identified in Section 3.1 of the SRP-LR for the RV bolting and vessel flanges exposed to containment air and is therefore acceptable to the staff.

3.1.3.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the RV components for the extended period of operation for the St. Lucie reactor units.

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in components that are fabricated from stainless steel, low-alloy steel with stainless steel cladding, Alloy 600 (core stabilizing lugs and stop lugs), and carbon steel with stainless steel cladding that are exposed internally to primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in control element drive mechanism nozzle tubes and motor housing lower end fittings, vent pipes, and incore instrumentation nozzle flange adaptors/upper flanges that are fabricated from Alloy 600 and exposed internally to primary treated water

- the Reactor Vessel Integrity Program to manage reduction in fracture toughness of RV beltline materials

- the Boric Acid Wastage Surveillance Program to manage loss of material in low-alloy steel closure head domes and flanges, primary inlet nozzles, nozzle support pads, shells, bottom heads, and carbon steel safe-ends that could be exposed to postulated leaks of the primary treated water

- the Boric Acid Wastage Surveillance Program to manage loss of mechanical integrity of closure studs, nuts, and washers that could be exposed externally to postulated leaks of the primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material of Alloy 600 core stabilizing lugs that are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material of low-alloy steel vessel flanges and RV studs, nuts, and washers that are exposed externally to containment air

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RV components, and serves a mitigative means of minimizing cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section

3.2.2.1 of Appendix B to the LRA) manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive RV components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all RV components that are made from Alloy 600 base metals that are susceptible to PWSCC. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, closure head domes and flanges, inlet and outlet nozzles and safe-ends, and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed to postulated leakage of the primary treated water from the RCS. This program is consistent with the applicant's surveillance program that is in effect in response to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluated this program in Section 3.0.5.4 of this SER.

The applicant credits the Reactor Vessel Integrity Program (Section 3.2.12 of Appendix B to the LRA) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. The staff's review of this AMP is provided in Section 3.1.0.5 of this SER.

3.1.3.3 Conclusion

The staff concludes that the applicant has demonstrated that the aging effects associated with RVs will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the program activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.1.4 Reactor Vessel Internals

The applicant describes its AMR of the RVIs in LRA Section 3.1.4, "Reactor Vessel Internals." The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the RVI components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4.1 Summary of Technical Information in the Application

In Section 3.1.4 and Table 3.1-1 of the LRA, the applicant identified that the RVI components are fabricated from stainless steel and CASS. In Table 3.1-1 of the LRA, the applicant identified that the RVI components are exposed internally to primary treated water. The applicant defined this internal environment in Table 3.0-1 of the LRA.

3.1.4.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable for the passive RVI components that are within the scope of license renewal.

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity
- loss of preload
- dimensional change

In accordance with Section 3.1.3 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RVI components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.4.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified that the following AMPs or activities will be used to manage the aging effects applicable for the RVI components during the period of extended operation.

- Chemistry Control Program
- Reactor Vessel Internals Inspection Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

3.1.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA, as well as pertinent sections of Appendices A and B to the LRA, regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RVIs, and associated components, will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the RVI components that are within the scope of license renewal and require an AMR, details the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

3.1.4.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive RVI components within the scope of license renewal.

- cracking in components that are fabricated from stainless steel or CASS and are exposed to primary treated water environments
- reduction of fracture toughness in components that are fabricated from stainless steel or CASS and are exposed to primary treated water environments
- loss of material due to wear in components that are fabricated from stainless steel that are exposed to primary treated water environments
- loss of preload of the hold down ring that is fabricated from stainless steel and is exposed to primary treated water environments
- loss of mechanical closure integrity of bolts, core support lug bolts, and tie rods that are fabricated from stainless steel and are exposed to primary treated water environments
- dimensional changes of components that are fabricated from stainless steel and are exposed to primary treated water environments (due to void swelling)

Fatigue. The potential for cracking to occur in stainless steel and CASS RVI materials is predominantly a phenomenon of thermal fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Section 4.3.1 of the LRA. The staff's evaluation of the TLAA is given in Section 4.3 of this SER.

Aging of Reactor Vessel Internals Components Exposed to the Primary Treated Water Environment. Cracking of the RVIs due to either SCC or IASCC is an applicable aging effect for RVIs. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for bolting, given the potential for occluded environmental conditions in crevice areas. IASCC is SCC that is enhanced by exposure of the materials to ionizing radiation. Cracking of the RVIs may also occur due to thermal fatigue, as discussed in the preceding paragraph. In LRA Table 3.1-1, the applicant has identified cracking as an applicable aging effect for RVIs. This is acceptable to the staff because it accounts for the aging effects of cracking due to SCC or IASCC, and because it is in accordance with Section 3.1 of the SRP-LR which states that cracking is an applicable aging effect for all PWR RVIs.

Reduction in fracture toughness due to thermal embrittlement is an aging effect requiring management for the period of extended operation. Thermal embrittlement refers to gradual and progressive changes in the micro structure and properties of a material due to exposure to elevated temperatures for an extended period. The RVI components fabricated from CASS are potentially subject to reduction in fracture toughness due to thermal embrittlement, as addressed in the Interim Staff Guidance, License Renewal Issue No. 98-0030, "Thermal Embrittlement of Cast Austenitic Stainless Steel Components," dated May 19, 2000. The applicant identified that the CASS components in the RVIs for St. Lucie Units 1 and 2 include flow bypass inserts (Unit 2 only), single tube CEA shrouds, and core support columns (Unit 1 only). The applicant identified that reduction of fracture toughness is an applicable aging effect for all RVIs made out of CASS. This is acceptable to the staff because it accounts for the aging effects of thermal embrittlement of the fracture toughness properties of CASS RVIs, and because it is in accordance with Section 3.1 of the SRP-LR, which states that reduction of fracture toughness is an applicable aging effect for all PWR RVIs fabricated from CASS.

Reduction in fracture toughness may also occur due to irradiation embrittlement. Exposure to high energy neutrons can cause changes in the properties of stainless steel used in RVIs. Neutron irradiation can produce changes in mechanical properties by increasing yield and ultimate strength, and decreasing ductility and fracture toughness of RVI component materials. In Section 3.1.4.2.2 of the LRA, the applicant listed several RVI components (which include the core support barrels, core support barrel upper flanges, alignment keys, core shroud assemblies, core support plates, etc.) that are located in the active fuel region and are exposed to high fluence, thus causing the components to be potentially susceptible to irradiation embrittlement. This is acceptable to the staff because it accounts for the aging effects of irradiation embrittlement on the fracture toughness properties of stainless steel RVIs, and because it is in accordance with Section 3.1 of the SRP-LR, which states that reduction of fracture toughness is an applicable aging effect for RVIs fabricated from stainless steel that are exposed to fluences greater than 1×10^{21} n/cm^2.

According to Section 3.1 of the SRP-LR, loss of material due to erosion or general corrosion is not normally an issue for austenitic stainless steel materials in the PWR environment because the materials are inherently resistant to erosion and general corrosion. The staff compared the applicant's AMRs for austenitic stainless steel RVIs components to corresponding AMRs in Section 3.1 of the SRP-LR. These AMRs were found to be consistent with Section 3.1 of the SRP-LR, and therefore are acceptable to the staff.

Loss of material from wear of RVIs occurs due to relative motion between the interfaces and mating surfaces of components caused by flow-induced vibration during plant operation, differential thermal expansion and contraction movements during plant heat up and cool down, and changes in power operating cycles. The severity of the wear depends on the frequency of motion, duration, and component loadings. The applicant identified loss of material due to mechanical wear for several RVI components, including fuel alignment plates (Unit 2 only), fuel alignment plate guide lugs (Unit 1 only), fuel alignment plate guide lug inserts, hold down rings, CEA extension shaft guides, core support barrel upper flanges, core support barrel alignment keys, fuel alignment pins, and snubber spacer blocks. This is acceptable to the staff because (1) it is consistent with Section IV.B3 of the GALL Report, Volume 2, which states that loss of material is an applicable aging effect for these RVI components of PWRs, and (2) it specifically accounts for loss of material that could be induced by wear.

Stress relaxation may be defined as the unloading of preloaded components under conditions of long-term exposure of RVI materials to high constant strain, elevated temperature, and/or neutron irradiation. Loss of preload due to stress relaxation is an applicable aging effect for those RVIs with substantial preload. A loss of preload in these components could result in higher cyclic and transient loads and a loss of function. The combination of bolt stress relaxation, changes in transient and high cycle vibration of the RVIs, and the effects of increased RVI fatigue susceptibility may be significant for the license renewal period. The applicant identified the hold down rings as the RVI components that are susceptible to loss of preload due to stress relaxation. This is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR, which states that loss of preload is an applicable aging effect for the RVI hold down rings.

Loss of mechanical closure integrity of fuel alignment plate guide lug bolts (Unit 1 only), fuel alignment plate guide lug insert bolts, and CEA shroud bolts can occur due to cracking and stress relaxation. Loss of mechanical closure integrity associated with the core shroud tie rods (Unit 1 only) and snubber bolts (Unit 1 only) can occur due to cracking, reduction in fracture toughness (irradiation embrittlement), and stress relaxation. The identification of loss of mechanical closure integrity due to cracking and stress relaxation for these RVI components is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR.

Void swelling is defined as a gradual increase in dimensions of the RVIs. Under reactor internals irradiation conditions, helium is generated as a nuclear transmutation reaction product. At sufficiently high temperatures, helium bubbles expand to a critical diameter and coalesce (unite) into larger bubbles. These bubbles create void areas (gaps) in the materials and may result in the swelling of the material. Swelling changes the dimensions of the material and may affect the ability of the particular RVI component to perform its intended functions. Although void swelling has not been observed to date, the staff is concerned that void swelling may become significant during the period of extended operation. Until the industry has developed sufficient data to demonstrate that void swelling is not a significant aging mechanism, the staff believes that void swelling should be considered significant, and applicants for license renewal should describe their AMP to address void swelling. In LRA Table 3.1-1, the applicant has identified change in dimension as an applicable aging effect for some of the RVIs. The identification of dimensional changes due to void swelling for these RVI components is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR.

Uncertainty currently exists relative to the prediction of void swelling in PWR conditions. This uncertainty is based on the fact that existing swelling data have been obtained from materials that were not irradiated in a PWR environment. Void swelling is a complex function of neutron flux, neutron fluence, operating temperature, operating stress, material composition, and the material fabrication process. However, the key environmental factors influencing void swelling are cumulative radiation dose and temperature.

Presently, data are not available to ascertain a specific threshold for the onset of void swelling in solution annealed Type 304 stainless steel in a PWR environment. However, data on the onset of void swelling in solution annealed and 10, 20, and 30 percent cold-worked Type 304 stainless steel exposed to a breeder reactor environment are available. The onset of void swelling estimated to start at fluence levels of approximately 4 to 8 x 10^{22} n/cm^2 (E > 1 MeV) at a temperature of 440 °C (824 °F). (*Effects of Radiation on Materials,* ASTM STP 725, "Comparison of High-Fluence Swelling Behavior of Austenitic Stainless Steels," page 484.) PWRs operate at approximately 315 °C (599 °F), well below 440 °C (824 °F). FPL indicated that its Reactor Vessel Internals Inspection Program includes an evaluation of dimensional changes due to void swelling. The applicant further stated that if the dimensional changes due to void swelling are determined to be significant, program inspections would be performed.

The applicant is currently participating in industry programs to address the significance of void swelling. These programs address both the physical phenomenon of void swelling, as well as the safety significance. The Reactor Vessel Internals Inspection Program (Section 3.1.4 of

Appendix B to the LRA) addresses the applicant's actions with respect to identification and inspection of RVI components susceptible to void swelling, including participation in the industry's program to address this issue. The staff's evaluation of this AMP is documented in Section 3.1.4.2.2 of this SER.

3.1.4.2.2 Aging Management Programs

The applicant indicated that the following programs will be used to manage the aging effects applicable to the RVI components for the extended period of operation for the St. Lucie reactor units.

- the Chemistry Control Program, ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and the Reactor Vessel Internals Inspection Program to manage cracking in RVI components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Reactor Vessel Internals Inspection Program to manage reduction in fracture toughness of RVI components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material and loss of preload in RVI components that are fabricated from stainless steel and are exposed internally to primary treated water

- the Chemistry Control Program, ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and the Reactor Vessel Internals Inspection Program to manage loss of mechanical closure integrity of RVI components that are fabricated from stainless steel and are exposed internally to primary treated water

- the Reactor Vessel Internals Inspection Program to manage dimensional changes due to void swelling of RVI components that are fabricated from stainless steel and are exposed internally to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RVI components, as well as serving as a mitigative means of minimizing loss of material and cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is documented in Section 3.0.4.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section B.3.2.2.1 of Appendix B to the LRA) manages the aging effects of loss of material, cracking, loss of preload, and reduction in fracture toughness. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsection IWB. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The staff's evaluation of this AMP is documented in Section 3.0.4.3 of this SER.

The Reactor Vessel Internals Inspection Program (Section 3.1.4 of Appendix B to the LRA) manages aging effects of cracking due to IASCC and SCC, reduction in fracture toughness due to irradiation and thermal embrittlement, loss of mechanical closure integrity of bolted joints on accessible parts of the St. Lucie Units 1 and 2 RVI components, and dimensional changes due to void swelling. This program consists of a surface examination (VT-1 or enhanced VT-1) that typically includes remote visual inspections. This program also provides screening criteria to determine the susceptibility of CASS parts to thermal embrittlement based on the casting method, molybdenum content, and percent ferrite. The staff's evaluation of this program is in Section 3.1.0.7 of this SER.

3.1.4.3 Conclusions

The staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA as it relates to the applicant's AMRs for the St. Lucie RVI components. In addition, the staff reviewed the Reactor Vessel Internals Inspection Program. The staff concludes that the applicant has demonstrated that the aging effects associated with the RVIs will be adequately managed so that there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5 Reactor Coolant Pumps

In Section 3.1.5, "Reactor Coolant Pumps," of the LRA, the applicant describes its AMR of the RCPs. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the RCPs will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5.1 Summary of Technical Information in the Application

In Section 3.1.5 and Table 3.1-1 of the LRA, the applicant identifies the RCP components that require an AMR. These components consist of casings, covers, lower seal heat exchanger tubes, and bolting. In addition, the applicant states that these components are fabricated from either stainless steel, cast stainless steel, or low-alloy steel. In Table 3.1-1 of the LRA, the applicant states that the RCP components are exposed internally to primary treated water and other treated water environments and externally to either the containment atmosphere or postulated leaks of primary treated water (i.e., borated water leakage environments). The applicant defines these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA.

3.1.5.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects applicable to the passive RCP components which are within the scope of license renewal.

- cracking
- reduction in fracture toughness from thermal embrittlement
- loss of material
- loss of mechanical closure integrity

In Section 3.1.5 of the LRA, the applicant provides the results of its review of industry experience and NRC generic communications relative to the RCP components. The applicant states that the review ensured that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for RCP components at St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.5.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following AMPs or activities that will be used to manage the aging effects applicable to the RCP components during the periods of extended operation.

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD ISI program
- Boric Acid Wastage Surveillance Program

3.1.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.5 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended functions of the RCP components will be maintained consistent with the CLB throughout the period of extended operation.

In Table 3.1-1 of the LRA, the applicant lists the RCP components that are within the scope of license renewal and require AMRs, details the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

3.1.5.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects applicable to the passive RCP components within the scope of license renewal

- cracking due to flaw growth and stress corrosion in components that are fabricated from stainless steel and are exposed internally to primary treated water environments

- cracking and reduction in fracture toughness in components that are fabricated from CASS and are exposed internally to primary treated water

- loss of material due to MIC and pitting corrosion for the RCP lower seal heat exchanger that is exposed internally to other treated water

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant's TLAA for the components is addressed in Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class I Components," of the LRA. The staff's evaluation of the TLAA is provided in Section 4.3 of this SER.

Aging of RCP Components Exposed to Internal Environments. Austenitic metals, including austenitic stainless steel, are known to be susceptible to SCC if the materials are exposed to the primary treated coolant (i.e., if the materials are known to be susceptible to PWSCC), or if the surface of the RCP component comes in contact with oxygenated liquids or liquids with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. In Table 3.1-1 of the LRA the applicant has identified cracking as an applicable effect for the surfaces of RCP stainless steel and cast stainless steel components that are exposed to treated primary water. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1), and is evaluated by the staff in Section 4.3.1 of this SER.

The applicant has stated that CASS components may be susceptible to loss of fracture toughness as a result of thermal aging. Thermal aging (thermal embrittlement) refers to the gradual and progressive changes in the micro structure and properties of a material due to exposure at elevated temperatures for an extended period of time. The applicant has identified that reduction of fracture toughness is an additional aging effect for the RCP components fabricated from CASS.[7] The applicant's identification of reduction of fracture toughness as an applicable effect for the CASS RCP components that are exposed to treated primary water is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable. The applicant proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage reduction of fracture toughness in the RCP components. The CASS RCP casings and covers do not require an AMP to manage thermal embrittlement beyond the examinations programmatically required by ASME Section XI, as modified by Code Case N-481. This is consistent with the examination guidelines in the staff's ISG[8] on aging of RCP casings and covers fabricated from CASS and is therefore acceptable. The staff's evaluation of the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program is discussed in Section 3.0.5.3 of this SER.

The aging effects that can cause loss of material for the RCP lower seal heat exchanger are MIC and pitting corrosion. Loss of material due to MIC and pitting corrosion was identified by the applicant as an aging effect for the outside diameter of the RCP lower seal heat exchanger tubing. The applicant proposed to use the Chemistry Control Program to manage MIC and pitting corrosion of the RCP components. Based on the information provided above, the staff finds that the applicant adequately identified loss of material as an applicable aging effect of the

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7 The other aging effect is cracking, which was assessed by the staff in the previous paragraph.

8 Letter from C.I. Grimes (NRC) to D.J. Walters (NEI), License Renewal Issue No. 98-0030, "Thermal Embrittlement of Cast Austenitic Stainless Steel Components," Project No. 690, May 2000.

RCP lower seal heat exchanger tubing, and that the Chemistry Control Program is acceptable to manage loss of material. The staff's evaluation of the Chemistry Control Program is discussed in Section 3.0.5.5 of this SER.

Aging of RCP Components Exposed to External Environments. The RCP bolting is made out of low-alloy steel (ferritic fasteners). These fasteners are stressed (preloaded) to ensure the integrity of the pressure boundary in RCP bolted connections. The applicant identified stress relaxation for RCP low-alloy steel components exposed to containment air as a potential mechanism that could result in a loss of mechanical closure integrity for these materials. This is a phenomenon in which the preloaded stress applied to the bolts for structural integrity loosens over time. This aging effect is consistent with the aging effects identified in Section IV.C2 of the GALL Report, Volume 2, for low-alloy steel bolting materials and is therefore acceptable to the staff.

The second mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is aggressive attack or corrosion as a result of exposure to potential leaks of the treated (borated) primary coolant. Industry experience and NRC generic communications have demonstrated that ferritic low-alloy steel materials may be extremely susceptible to loss of material/aggressive corrosive attack when exposed to borated water. Consistent with Section 3.1.5 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low-alloy steel bolting materials covers this aging effect. This aging effect is consistent with the aging effects identified in Section 3.1 of the SRP-LR for low-alloy steel bolting materials and is therefore acceptable to the staff.

3.1.5.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the RCP components for the extended periods of operation for the St. Lucie reactor units.

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in RCP components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water
- the Chemistry Control Program to manage loss of material in RCP components that are fabricated from stainless steel and are exposed internally to other treated water
- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage reduction of fracture toughness in RCP components that are made from CASS and are exposed to primary treated water
- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of mechanical closure integrity of material in low-alloy steel bolting that could be exposed to an external environment of containment air
- the Boric Acid Wastage Surveillance Program to manage loss of mechanical closure integrity of material in low-alloy steel bolting that could be exposed to postulated leaks of primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RCP components and serves as a mitigative means of minimizing loss of material and cracking in these components. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5 of this SER.

Based on the ISG, the CASS RCP casings and covers do not require an AMP to manage thermal embrittlement beyond the examinations programmatically required by ASME Section XI, as modified by Code Case N-481. Accordingly, the applicant has proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, as modified by Code Case N-481 (Section 3.2.2.1 of Appendix B to the LRA), to manage reduction of fracture toughness in RCP components fabricated from CASS. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program also manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive RCP components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) also manages loss of mechanical closure integrity in low-alloy steel bolting that could be exposed to containment air as identified in Table 3.1-1 of the application. This program manages aging effects applicable to specific Class 1, 2, and 3 components, including managing aging effects applicable to low-alloy steel bolting. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of mechanical integrity in low-alloy steel bolting that is exposed to postulated leakage of primary treated water from RCS. This program is consistent with the applicant's surveillance program that is, in effect, in response to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluated this program in Section 3.0.5 of this SER.

3.1.5.3 Conclusions

The staff has reviewed the information in Section 3.1.5 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the RCP components. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RCP components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6 Steam Generators

The applicant describes its AMR of the SGs in LRA Section 3.1.6, "SGs." The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the SGs will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The nuclear steam supply system in St. Lucie Units 1 and 2 uses SGs to transfer the heat generated in the RCS to the secondary system. The steam generator is a vertical U-tube heat exchanger with the reactor coolant on the tube side and the secondary fluid on the shell side. Reactor coolant enters the SG through the inlet nozzle, flows through tubes, and exits through two outlet nozzles. Divider plates in the lower head of the SGs separate the inlet and outlet plenums. The plenums are a carbon steel forging with stainless steel clad; the reactor coolant side of the tubesheet is cladded with nickel-chromium-ferrite alloy. The tube ends are welded on the primary side of the tubesheet, and the tube inside the tubesheet bore is expanded to form an interference fit to resist tube pullout. Feedwater enters the SG shell side through the Feedwater nozzle where it is distributed via a Feedwater distribution ring that directs flow to the downcomer in the SGs. The downcomer is the annular passage formed by the inner surface of the SG shell and the cylindrical shell which encloses the tube bundle. Upon exiting from the bottom of the downcomer, the secondary flow is directed upward over the vertical tube bundle. Heat transferred from the primary side converts a portion of the secondary flow into steam. A saturated steam/water mixture enters the moisture separator section in the top of the SG where the water is removed from the mixture and dried in the evaporator. Dry steam exits the steam outlet nozzle and is piped to the turbines.

St. Lucie Unit 1 has two replacement SGs manufactured by Babcock and Wilcox International which were installed in December 1997. The replacement SGs include design features and materials that minimize potential corrosion and cracking. For example, the tube is fabricated with thermally treated Alloy 690 material which has better corrosion resistance than the mill-annealed Alloy 600 material used in the original SGs. The tube is supported by the stainless steel lattice bars which reduce corrosion at the tube support intersections. The hydraulic expansion joints are installed full length in the tubesheet to minimize crevice corrosion and cracking in the tubesheet. In addition, the replacement steam generator (RSG) design addresses industry Feedwater distribution system problems such as waterhammer, thermal stratification, erosion, and internal Feedwater header collapse. The RSG distribution system satisfies all the current (at the time of design) NRC recommendations with respect to waterhammer, provides flow stratification mitigation, and addresses industry concerns regarding corrosion, corrosion cracking, thermal fatigue, and material erosion. Furthermore, the RSG allows for inspection access to the Feedwater header region through tunnels and ladders at each drum manway location.

St. Lucie Unit 2 has two original Combustion Engineering model 3410 SGs that have tubes fabricated from the mill-annealed Alloy 600 material. The tube is supported by the carbon steel lattice bars. The tube is also hydraulically expanded in the tubesheet to minimize crevice corrosion. The detailed description of the SGs are provided in the Unit 1 UFSAR, Section 5.5.1, and the Unit 2 UFSAR, Section 5.4.2. The staff's review of the applicant's scoping results of the SG components is provided in Section 2.3.1.6 of this SER.

3.1.6.1 Summary of Technical Information in the Application

In Section 3.1.6 and Table 3.1-1 of the LRA, the applicant identified that the SG components are fabricated from carbon steel, stainless steel, low-alloy steel, low-alloy steel and carbon steel with stainless steel cladding, low-alloy steel with Alloy 600 cladding, and Alloy 600/690. In Table 3.1-1 of the LRA, the applicant identified that the SG components are exposed internally to primary and secondary treated water and externally to containment air and borated water leaks. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-

2 of the LRA, respectively.

As stated in the St. Lucie UFSARs, the SGs in both St. Lucie units are designed and fabricated in accordance with Section III of the ASME Boiler and Pressure Vessel Code specifications. The SG components, their intended functions, the materials of construction, and environments are described in Table 3.1-1 of the LRA. The SG intended functions include pressure boundary integrity, heat transfer, flow distribution, structural support, and throttling. The inside surface of the primary and secondary side of the SGs is exposed to an internal environment of treated water. The outside surface of the SGs is exposed to external environments of containment air and potential borated water leaks. The materials of construction of the SG components include stainless steel, low-alloy steel, carbon steel, Alloy 600, and Alloy 690.

The applicant stated that the St. Lucie Units 1 and 2 SG designs do not include the Feedwater impingement plates and supports and tube support plates. Also, Feedwater inlet rings and supports will not require an AMR because these components 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.

3.1.6.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified cracking, loss of material, and loss of mechanical closure integrity as the aging effects on SG components that require aging management during the period of extended operation.

Cracking. The applicant stated that industry experience has shown that Alloy 600 SG tubing is susceptible to PWSCC, secondary side IGA, and IGSCC. SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. The applicant identified cracking caused by flaw growth and stress corrosion as an aging effect requiring management for the period of extended operation. Growth of original manufacturing flaws over time due to service loading can also cause cracking. The applicant stated that for the RSGs, specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from SG components. In addition, to reduce the susceptibility of SG materials to SCC, the applicant prevents sensitized stainless steels from coming in contact with an aggressive environment at the St. Lucie Nuclear Plant.

Industry operating experience has shown SG Feedwater nozzles to be susceptible to cracking due to fatigue. Since this particular failure mechanism has been experienced, aging management of fatigue cracking of the SG Feedwater nozzle is required for the period of extended operation. Cracking caused by fatigue is identified as a TLAA and is addressed in Subsection 4.3.1 of the LRA.

Industry experience has also shown SG tube plugs to be susceptible to PWSCC. The root cause of the PWSCC has been attributed to tube plugs fabricated from improperly heat-treated Alloy 600 material. At St. Lucie, two cases of leaking tube plugs were recorded, both in the original Unit 1 SGs in 1996. In Unit 2, one of the welded shop plugs was replaced in 1985 due to leakage. The applicant considers PWSCC to be an aging effect that requires management for the tube plugs.

The applicant stated that SG primary instrument nozzles, fabricated from Alloy 600, have not exhibited aging effects caused by PWSCC. This can be attributed to their exposure to lower temperatures during normal power operation when compared to the pressurizer and RCS hot-leg instrument nozzles and RV upper head CRDM housing tubes. The applicant stated that it appears that PWSCC of the Alloy 600 instrument nozzles on SGs is not likely to be significant during the period of extended operation. However, since Alloy 600 in general is susceptible to PWSCC, the applicant considers PWSCC to be an aging effect requiring management for the primary instrument nozzles on SGs.

Loss of Material. The applicant identified loss of material as an aging effect for the SGs requiring management during the period of extended operation. The aging mechanisms that can cause loss of material for the SGs are general corrosion, crevice corrosion, pitting corrosion, FAC, mechanical wear, and aggressive chemical attack.

The applicant identified general corrosion, pitting corrosion, and crevice corrosion as aging mechanisms for internal surfaces of carbon steel and low-alloy steel components on the SG secondary side. These degradations on the secondary-side surfaces are mitigated by maintaining adequate secondary-side chemistry controls.

The applicant stated that pitting of the secondary side of the SG tubing has occurred at a number of older plants. The location of the pitting is generally in the sludge pile region on the secondary face of the tubesheet. Pitting is not expected to be a significant aging mechanism for the St. Lucie Units 1 and 2 SGs because of the low amount of copper and chlorides in the secondary system, careful control of the oxidizing in the secondary water, and routine removal of tubesheet sludge via lancing.

The applicant identified FAC as a potential aging mechanism for loss of material in nozzles and safe-ends of Feedwater, steam outlet, and blowdowns and carbon steel tube support lattice bars (Unit 2 only). Although neither the industry nor the St. Lucie plant-specific operating experience includes any reports of loss of material in SG Feedwater, steam outlet, or blowdown nozzles and safe-ends, they are exposed to conditions conducive to FAC and are considered for aging management.

The applicant identified loss of material caused by tube wear at contacts with tube support straps. Therefore, tube wear is an aging mechanism that requires management. The applicant also identified loss of material caused by aggressive chemical attack as an aging effect requiring management for external surfaces of carbon steel components exposed to borated water leaks.

Loss of Mechanical Closure Integrity. The applicant identified loss of mechanical closure (bolting) integrity as an aging effect that requires aging management. Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack. The applicant stated that loss of mechanical closure integrity due to aggressive chemical attack has been observed in the industry and is the most common aging effect of concern for ferritic fasteners.

In accordance with Section 3.1.6 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the SGs and associated components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.6.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified the following six AMPs to manage the above aging effects associated with the SG components.

(1) ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
(2) Boric Acid Wastage Surveillance Program
(3) Chemistry Control Program
(4) Flow-Accelerated Corrosion Program
(5) SG Integrity Program
(6) Alloy 600 Inspection Program

The applicant concluded that these AMPs will manage the effects of aging associated with the SG components so that the intended functions of the SG components will be maintained consistent with the CLB under all design loading conditions during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant addressed cracking caused by fatigue of SG components as a TLAA item which is addressed in Section 4.3.1 of the LRA. The staff has evaluated the aging management of the metal fatigue issue as part of the TLAA review in Section 4.3 of this SER.

3.1.6.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.6 and Table 3.1-1 of the LRA, pertinent sections of Appendices A and B to the LRA, and the September 26, 2002, response to the staff's RAI regarding the applicant's demonstration that the effects of aging associated with the SG components will be adequately managed so that there is reasonable assurance that the intended functions of the SG components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Specifically, the staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and AMPs for the SG components in Section 3.1.6 and Table 3.1-1 of the LRA. Table 3.1-1 of the LRA lists the SG components that are within the scope of the license renewal and identifies the aging effects that require management.

3.1.6.2.1 Aging Effects

The staff finds that the aging effects identified in Section 3.1.6 and Table 3.1-1 of the LRA are acceptable because they are consistent with previously accepted staff positions. However, the staff raised several questions regarding certain aging effects associated with the AMPs.

The staff noted that in Table 3.1-1 of the LRA, the applicant specified that the external surface of the primary instrument nozzles will be in the leaking borated water environment. However, there was no aging effect and associated AMP was identified for the primary instrument nozzles in this external environment. The applicant responded that the primary instrument nozzles are fabricated from either Alloy 600 or Alloy 690 material. Alloy 600 and Alloy 690 are nickel-based alloys which are not susceptible to boric acid wastage. As such, there is no aging effect requiring management for the primary instrument nozzles exposed to an external environment of borated water leaks. The staff noted that the applicant has identified the Alloy 600 Inspection Program, Chemistry Control Program, and ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program to manage PWSCC of the primary instrument nozzles. Under the inspection AMPs, the staff believes that any potential degradation occurring at the primary instrument nozzles caused by borated acid corrosion could be detected and repaired, if necessary. The staff finds this issue closed.

The staff requested clarification on why loss of material due to boric acid corrosion (on the external surface) was not identified as an aging effect for the secondary manway and manhole closure covers, shell assembly, Feedwater nozzles and safe-ends, steam outlet nozzles and safe-ends, and primary heads. The applicant responded that the primary heads are potentially exposed to an external environment of borated water leaks. Accordingly, loss of material is identified as an aging effect requiring management, and the Boric Acid Wastage Surveillence Program provides assurance that this aging effect is managed for the period of extended operation. The SG secondary manway and manhole closure covers, shell assemblies, Feedwater nozzles and safe-ends, and steam outlet nozzles and safe-ends are not considered to be susceptible to borated water leaks because they are isolated from potential RCS leaks by the SG geometry. The geometry of the SG primary head and the physical distance between the primary manways and the upper and lower shells essentially eliminate the potential for boric acid exposure to these parts. The staff finds that the applicant's conclusion that loss of material due to boric acid corrosion is not an aging effect for the aforementioned components is acceptable because these components are isolated from potential RCS leaks, thereby eliminating the potential for loss of material due to boric acid exposure.

The staff noted that in Table 3.1-1 of the LRA, cracking was identified as an aging effect for Unit 1 stainless steel tube support lattice bars, but cracking was not identified as an aging effect for Unit 2 carbon steel tube support lattice bars. The staff requested the applicant to clarify why cracking is not applicable to the Unit 2 tube support lattice bars. The applicant stated that carbon steel components are not considered to be susceptible to cracking in a secondary-side treated water environment. As such, cracking is not identified as an aging effect requiring management for the St. Lucie Unit 2 carbon steel tube support lattice bars. The staff noted that in Section 3.1.6 of the LRA, the applicant identified loss of material caused by FAC for the carbon steel tube support lattice bars in Unit 2 SGs. The applicant has identified the SG Integrity Program to manage the corrosion of the tube support lattice bars. Specifically, the applicant credits periodic tube bundle flushing to minimize FAC of the lattice bars as discussed in Section 3.1.6.2.2 of this SER. The staff finds this issue closed because the applicant has identified the SG Integrity Program to manage degradation in the tube support lattice bars in the Unit 2 SGs.

The staff requested the applicant to clarify why wall thinning attributable to erosion was not applicable as an aging effect for the secondary manways and handholes. The applicant stated that the design of the secondary manways and handholes precludes the potential for wall thinning due to erosion. The secondary manways and handholes are located in areas of large cross section where velocity is low and erosion is not an aging concern. Plant-specific experience has confirmed that these components are not susceptible to this aging effect. The staff agrees with the applicant's conclusion because the location of the manways and handholes precludes wall thinning in these components.

In NRC IN 90-04, "Cracking of the Upper Shell-to-Transition Cone Welds in SGs," the staff states that if general corrosion or pitting of the SG shell is known to exist, the inspection program in Section XI of the ASME Code may not be sufficient to differentiate isolated cracks from inherent geometric conditions of the shell. The staff requested the applicant to describe additional inspection procedures for the upper and lower SG shells, if general corrosion or pitting exists in the St. Lucie SG shells. The applicant responded that, as indicated in Section 3.1.6.2.2 and Table 3.1-1 of the LRA, loss of material due to general corrosion and pitting corrosion has been identified as an aging effect for internal surfaces of carbon steel and low-alloy steel components on the SG secondary side, including the upper and lower shells. General corrosion and pitting corrosion of the SG upper and lower shells are mitigated by maintaining adequate secondary-side chemistry controls via the Chemistry Control Program. To date, loss of material due to general corrosion and pitting corrosion of the St. Lucie Units 1 and 2 SG upper and lower shells has not been experienced. Accordingly, no additional inspection procedures are required at this time. The staff considers this issue closed.

The staff requested the applicant to provide information on the tube plugs installed in the Unit 1 and 2 SGs, such as plug type and operating experience. The applicant responded that the RSGs use mechanical tube plugs fabricated from thermally treated Alloy 690 material. To date, there has been no evidence of tube plug degradation and no tube plugs have been replaced in the Unit 1 RSGs. The St. Lucie Unit 2 SGs use a combination of welded plugs and hydraulically expanded plugs. All hydraulically expanded tube plugs currently installed in the St. Lucie Unit 2 SGs are fabricated from thermally treated Alloy 690 material. Approximately 50 tubes in the Unit 2 SGs were plugged during manufacture (i.e., shop plugs) with welded tube plugs fabricated from Alloy 600 material. One of these welded shop plugs was replaced in 1985 due to leakage. In the UFSAR, the applicant stated that, should unacceptable tube degradation occur, the integrity of the reactor coolant boundary may be restored by installing a tube plug within the tube or tubesheet hole if removal of the tube is warranted. Should tube degradation occur that indicates the potential for tube severance, the tube may have a stake and tube plug installed. If the plugged tube severs, the stake is designed to reduce the possibility of tube-to-tube contact. The stakes, the plugs, and their installation are designed to function under all operating, transient, or test conditions of the SG. This installation takes into consideration maintaining integrity under vibrating loads and material compatibility with tube material subject to both reactor coolant and Feedwater system environments. As a result of the staff RAI, the applicant revised Table 3.1-1 of the LRA to include Alloy 600 as a material for fabrication of tube plugs. The staff notes that the aging effect related to the tube plugs will be managed under the SG Integrity Program. The staff finds the tube plug issue closed.

On the basis of the staff's review, the staff concludes that the applicant has identified all appropriate aging effects applicable to the SG components.

In addition, in Table 3.1-1 of the LRA, the applicant identified only thermally treated Alloy 690 as the material for tube plugs. The staff questioned the applicant regarding other materials that were used in tube plug fabrication.

3.1.6.2.2 Aging Management Programs

As discussed in Section 3.1.6.1.2 of this SER, the applicant indicated six AMPs to manage the aging effects associated with SG components. Of the six, the SG Integrity Program is a system-specific AMP and evaluated in Section 3.1.0.4 of this SER. The other five are common

AMPs and are evaluated separately in Section 3.0.5 of this SER.

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used for the SG components in order to minimize loss of material and cracking. This program was developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The applicant stated that the Chemistry Control Program provides assurance that pitting corrosion, general corrosion, crevice corrosion, PWSCC, IGA, and IGSCC are managed and that the intended functions of the SGs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects of loss of material, cracking, gross loss of preload, and reduction in fracture toughness. The scope of the Inservice Inspection Program for Class 1 and Class 2 components complies with the requirements of ASME Section XI, Subsections IWB, IWC, and IWD. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. ASME Section XI ISIs of components are intended to detect significant flaw growth. These inspections provide assurance that significant flaws do not exist or that a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that degradation in the SG components caused by pitting corrosion, general corrosion, crevice corrosion, PWSCC, IGA, and IGSCC is managed, and that the intended functions of the SG components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54-21(a)(3). The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Flow-Accelerated Corrosion Program (Section 3.2.9 of Appendix B to the LRA) is designed to manage loss of material from the carbon steel components due to FCA. The Flow-Accelerated Corrosion Program provides assurance that FCA of the internal surfaces of the SG Feedwater, steam outlet, blowdown nozzles and safe-ends, and Unit 2 carbon steel tube support lattice bars is managed and that the intended functions of the SGs will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation, as required by
10 CFR 54.21(a)(3). ff's evaluation of this AMP is described in Section 3.0.5.8 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) was developed by the applicant in response to NRC GL 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the RCPB does not lead to undetected loss of material on the external surface of reactor coolant piping and associated components, and particularly for those made of carbon steel or low-alloy steel. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of mechanical closure integrity due to aggressive chemical attack is managed and that the intended functions of the SGs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff's evaluation of this AMP is described in Section 3.0.5.4 of this SER.

The Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA), in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that potential PWSCC in the primary instrument nozzles on the SGs is managed and that the intended functions of the primary instrument nozzles will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

3.1.6.3 Conclusions

The staff has reviewed the information in Section 3.1.6 and Table 3.1-1 of the LRA as it relates to the applicant's AMRs for the SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the SG components will be adequately managed so that there is reasonable assurance that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Engineered Safety Features Systems

In Section 3.2, "Engineered Safety Features Systems," of the LRA, the applicant describes the AMR for the engineered safety features (ESF) systems. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the ESF systems. The staff reviewed Section 3.2 and the applicable portions of Appendices A, B, and C to determine whether the applicant provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3), for the ESF systems' SCs that are determined to be within the scope of license renewal and subject to an AMR.

The ESF systems include the following systems.

- containment cooling system
- containment spray system
- containment isolation system
- safety injection system
- containment post accident monitoring system

In Section 2.3.2 of the LRA, the applicant describes these systems and identifies the components requiring an AMR for license renewal. The staff's evaluation of the scoping methodology and the ESF systems' SCs included within the scope of license renewal and subject to an AMR is documented in Sections 2.1 and 2.3.2, respectively, of this SER. In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). In LRA Appendix B, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In LRA Appendix C, the applicant describes the process used to identify many of the applicable aging effects for the SCs that are subject to an AMR. In LRA Appendix D, the applicant states that no changes to the St. Lucie Technical Specifications have been identified. A review of each of these ESF systems follows.

3.2.1 Containment Cooling System

3.2.1.1 Summary of Technical Information in the Application

Section 2.3.2.1 of the LRA describes the containment cooling system as being designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a design-basis event (DBE). In addition, the containment fan cooling units continue to operate after a DBE event to remove heat and to reduce the pressure in the containment atmosphere. Heat removed from the containment is transferred to component cooling water. Containment cooling consists of four fan cooling units that are located outside the secondary shield wall inside each containment.

Containment cooling system components subject to an AMR include fan cooler housings and valves (pressure boundary only), heat exchangers, ducts, thermowells, flexible connections, drip pans, piping, and fittings. The intended functions of these containment cooling components include pressure boundary integrity and heat transfer. A complete list of containment cooling components requiring an AMR, the component intended functions, and the applicable AMPs is provided in Table 3.2-1 of the LRA.

3.2.1.1.1 Aging Effects

In Table 3.2-1 of the LRA, the applicant identifies stainless steel, carbon steel, copper, copper nickel, rubber-coated cloth, and galvanized carbon steel as the materials of construction for the containment cooling system components. Loss of material was identified as an applicable aging effect for carbon steel, copper, stainless steel, copper nickel, and galvanized carbon steel. Fouling was identified as an applicable aging effect for copper. Cracking was identified as an applicable aging effect for rubber-coated cloth. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel bolting (mechanical closure).

Austenitic stainless steel and galvanized carbon steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, no aging effects were identified for the surfaces of stainless steel thermowells (including drip pan thermowells), as well as ducts made of galvanized carbon steel, in air/gas or containment air environments.

Loss of material of carbon steel materials may occur in moist air environments. The applicant identified loss of material as an aging effect on the carbon steel containment fan cooler housings, valves, piping/fittings, Unit 1 containment fan cooler heat exchanger stubs/flanges, and containment fan cooler motor heat exchanger headers (Unit 1 only).

Copper material in contact with treated water may be susceptible to fouling, which if unattended, has the potential to block the flow of coolant through the tubes, thereby compromising the components' heat transfer function. The applicant identified the aging effect of fouling for the copper containment fan cooler heat exchanger tubes and containment fan cooler motor heat exchanger tubes (Unit 1 only) in an internal treated water—other environment.

Components made of copper, copper nickel, stainless steel, and carbon steel components are susceptible to loss of material in a treated water—other environment. The applicant identified loss of material as an aging effect for the copper containment fan cooler heat exchanger headers and end caps, stainless steel containment fan cooler heat exchanger vent plugs, Unit 1 carbon steel and Unit 2 copper nickel containment fan cooler heat exchanger stubs/flanges, Unit 2 carbon steel containment fan cooler closed cooling water system flanges, copper containment fan cooler motor heat exchanger tubes (Unit 1 only), carbon steel containment fan cooler motor heat exchanger headers (Unit 1 only), and carbon steel piping fittings.

Stainless steel material may be susceptible to loss of material when exposed to raw water drains. The applicant identified the aging effect of loss of material with the stainless steel drip pans. The applicant also identified cracking as the aging effect for the flexible connections made of rubber-coated cloth in air/gas environments.

Loss of material of carbon steel components may result from contact with borated water leaks. The applicant identified loss of material for carbon steel containment fan cooler housings, Unit 1 containment fan cooler heat exchanger stubs/flanges, containment fan cooler motor heat exchanger headers (Unit 1 only), valves (Unit 1 only), and piping/fittings when exposed to borated water leaks. The applicant similarly identified the aging effect of loss of material for the galvanized carbon steel ducts which are exposed to borated water leaks.

Loss of material of copper and copper nickel by corrosion may occur in a moist air environment in the containment building. The applicant, therefore, identified loss of material as an aging effect for the containment fan cooler heat exchanger with copper tubes, fins, headers, and end caps in Unit 2. The applicant identified loss of material in a treated water environment for copper and copper nickel in containment fan cooler heat exchanger header and, cap and stubs/flanges in both units, and for containment fan cooler heat exchanger copper tubes in Unit 1 only. The applicant identified the aging effect of loss of material in the stainless steel containment fan cooler heat exchanger vent plugs and frame side plates which are exposed to a containment air (wetted) environment.

Loss of mechanical closure integrity of carbon steel bolting may be caused by borated water leaks from other plant systems. The applicant identified this aging effect for the carbon steel bolting (mechanical closure) which is exposed to a borated water leak environment.

3.2.1.1.2 Aging Management Programs

The following AMPs are utilized to manage the aging effects in the containment cooling system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the containment cooling system will be adequately managed by these AMPs during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.2 Staff Evaluation

In Section 2.3.2, Section 3.2, and Table 3.2-1 of the LRA, the applicant describes its AMR of the containment cooling system for license renewal. The process of identifying aging effects is summarized in Appendix C of the LRA, and descriptions of the AMPs are provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment cooling system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.1, Table 3.2-1, and the applicable sections in Appendix C of the LRA. The staff determined that additional information was needed to complete its review.

In Table 3.2-1 of the LRA, the applicant identified no aging effects requiring management of carbon steel bolting exposed to containment air environments. By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects on closure bolting of the auxiliary system exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved. The staff considers that the applicant's response to RAI 3.3-1 addresses a similar concern for the closure bolting of the ESF systems, as well, because of the similar material-environment combination.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment cooling system's SCs with the environments described in Section 2.3.2.1 and Table 3.2-1 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments described.

3.2.1.2.2 Aging Management Programs

In Table 3.2-1 of the LRA, the applicant credited the following AMPs for managing the aging effects in the containment cooling system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material and fouling associated with the copper containment fan cooler heat exchanger headers and end caps, Unit 1 carbon steel containment fan cooler heat exchanger stubs/flanges, Unit 2 carbon steel containment fan cooler closed cooling water flanges, carbon steel containment fan cooler motor heat exchanger headers, and carbon steel piping/fittings which are exposed to treated water—other environments.

The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material associated with the carbon steel containment fan cooler housings, copper containment fan cooler heat exchanger tubes, copper containment fan cooler heat exchanger fins, containment fan cooler heat exchanger headers and caps, Unit 2 copper nickel containment fan cooler heat exchanger stubs/flanges, carbon steel valves, and piping/fittings which are exposed to the containment air (wetted). The Boric Acid Wastage Surveillance Program will be used to manage loss of material associated with the carbon steel components of containment fan coolers housing and heat exchangers; carbon steel valves, piping/fittings, and bolting; and galvanized carbon steel ducts which are exposed to borated water leaks. In addition, the Systems and Structures Monitoring Program will be used to manage the cracking associated with the flexible connections made of rubber-coated cloth.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-1, the staff concludes that the AMPs identified above will adequately manage the aging effects of the containment cooling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.3 Conclusions

The staff has reviewed the information in Section 2.3.2.1, and Table 3.2-1 of the LRA, and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment cooling system will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing aging effects, as required by 10 CFR 54.21(d).

3.2.2 Containment Spray System

3.2.2.1 Summary of Technical Information in the Application

In Section 2.3.2.2 of the LRA, the applicant describes the containment spray system as being designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a DBE. The containment spray system for each unit consists of two containment spray pumps that take suction from the refueling water tanks and spray borated water from nozzles located near the top of each containment structure. When the refueling water tank inventory is exhausted, the containment spray pump suction is switched to the containment recirculation sumps, and the shutdown cooling heat exchangers are used to remove heat from the recirculation water.

Chemicals are injected into the containment spray pump suction lines during containment spray operations to control pH and for iodine absorption. Unit 1 has a sodium hydroxide tank that supplies sodium hydroxide through eductors to the suction lines of the containment spray pumps. Unit 2 has hydrazine pumps that inject hydrazine from a hydrazine storage tank into the suction lines of the containment spray pumps. In addition, Unit 2 utilizes solid trisodium phosphate dodecahydrate in stainless steel mesh baskets located in the vicinity of the containment recirculation sumps to control post-accident pH.

Containment spray components subject to an AMR include refueling water tanks, sodium hydroxide tank, hydrazine tank, pumps and valves (pressure boundary only), heat exchangers, eductors, orifices, strainers, thermowells, spray nozzles, vortex breaker (Unit 1 only), rupture discs, sight glasses, piping, tubing, and fittings. The intended functions of containment spray components subject to an AMR include pressure boundary integrity, heat transfer, vortex prevention, spray, throttling, and filtration. A complete list of containment spray components requiring an AMR, the component intended functions, and the applicable AMPs is provided in Table 3.2-2 of the LRA.

3.2.2.1.1 Aging Effects

In Table 3.2-2 of the LRA, the applicant identifies aluminum, fiberglass-reinforced vinyl ester, stainless steel, cast iron, brass, nickel alloy, carbon steel with stainless steel cladding, glass, and carbon steel as the materials of construction for the containment spray system components. Loss of material was identified as an applicable aging effect for aluminum, stainless steel, cast iron, brass, and carbon steel. Cracking and delamination (including loss of adhesion) were identified as applicable aging effects for fiberglass-reinforced vinyl ester. Fouling was identified as an applicable aging effect for stainless steel. Cracking was identified as an applicable aging effect for stainless steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Aluminum material is designed to be corrosion resistant in dry air environments. Corrosion and cracking generally have not been a problem for aluminum or for stainless steel components in dry or moist environments. No aging effects were identified for the Unit 1 aluminum refueling water tank exposed to air/gas environments.

No aging effects were identified for the stainless steel components, such as the Unit 2 refueling water tank, sodium hydroxide storage tank (Unit 1 only), hydrazine storage tank (Unit 2 only), sodium hydroxide tank rupture disc (Unit 1 only), valves, piping/fittings and tubing/fittings, spray nozzles, containment spray pumps, eductors (Unit 1 only), hydrazine pumps (Unit 2 only), thermowells, rupture disc, orifices, and bolting (mechanical closure) which are exposed to air/gas, containment air, indoor not-air-conditioned, and outdoor environments.

Loss of material from corrosion can occur when stainless steel materials are in contact with raw water. However, if the raw water is well drained, stainless steel materials would not be susceptible to corrosion. Therefore, no aging effects were identified for the valves and piping/fittings which are part of the reactor cavity sump drains. Similarly, no aging effects were identified for nickel alloy piping exposed to raw water—drains or air/gas environments. Carbon steel with stainless steel cladding and glass are not susceptible to corrosion in treated water—other or air/gas environments. No aging effects were identified for sight glass (Unit 1 only) when exposed to these environments.

Brass material generally has not been a problem in indoor not-air-conditioned environments. No aging effects were identified for the containment spray pump cooler flex connectors (Unit 1 only) exposed to indoor not-air-conditioned environments. Similarly, no aging effects were identified for the bolting (mechanical closure) exposed to indoor not-air-conditioned, containment air, and outdoor environments.

Loss of material of aluminum materials from general corrosion may occur when in contact with treated water—borated environments. The applicant identified loss of material for the aluminum portion of the Unit 1 refueling water tank which is exposed to treated water—borated environments. The applicant also identified the aging effects of cracking and delamination for the fiberglass portion of the Unit 1 refueling water tank when exposed to treated water—borated environments.

Loss of material and cracking of stainless steel in a treated water environment are possible aging effects under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low-flow conditions could lead to loss of material and cracking of stainless steel in treated water. The applicant identified the aging effects of loss of material for the Unit 2 stainless steel refueling water tank, containment spray pumps, eductors (Unit 1 only), orifices, and refueling water tank strainers which are exposed to treated water—borated environments. For the same treated water environment and an elevated temperature in excess of 140 °F, the applicant also identified the aging effects of loss of material and cracking for the stainless steel valves, piping/fittings, tubing/fittings, and thermowells. For containment spray pump cooler tubes exposed to treated water environments, the tubes may be susceptible to fouling, which if unattended, has the potential to block the flow of coolant through the tubes and, in some cases, to produce corrosive environments that could lead to a loss of tube material. The applicant identified the aging effects of loss of material and fouling for the stainless steel containment spray pump cooler tubes which are exposed to a treated water—borated environment for the inside diameter and a treated water—other environment for the outside diameter.

Cast iron, brass, and aluminum are susceptible to loss of material when exposed to a treated water environment. The applicant identified the aging effect of loss of material for cast iron containment spray pump cooler shells (Unit 1 only) and brass containment spray pump cooler flex connectors (Unit 1 only) which are exposed to treated water—other environments, and for the aluminum refueling water tank vortex breaker (Unit 1 only) which is exposed to a treated water—borated environment.

Loss of material of aluminum materials by corrosion may occur in a moist air environment. The applicant identified the aging effect of loss of material for the Unit 1 refueling water tank exposed to the outdoor environment. Cast iron material may be susceptible to loss of material in an indoor not-air-conditioned or a borated water leaks environment. The applicant identified the aging effect of loss of material for the containment spray pump cooler shells (Unit 1 only) which are exposed to these environments.

Plant experience has identified the potential for SCC and loss of material due to pitting corrosion on stainless steel components located in the emergency core cooling system (ECCS) pipe tunnel. The applicant identified the aging effect of loss of material for the piping/fittings which are located in the outdoor ECCS pipe tunnel.

Carbon steel components are susceptible to loss of material due to boric acid corrosion of external surfaces. The applicant identified the aging effect of loss of material for the carbon steel sight glass (Unit 1 only) which is exposed to an indoor not-air-conditioned or a borated water leaks environment. Finally, loss of mechanical closure integrity of carbon steel bolting may be caused by borated water leaks from other plant systems. The applicant identified this aging effect for the carbon steel bolting (mechanical closure) that is exposed to a borated water leaks environment.

3.2.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment spray system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

Description of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the containment spray system will be adequately managed by these AMPs for the period of extended operation.

3.2.2.2 Staff Evaluation

In Section 2.3.2.2, Section 3.2, and Table 3.2-2 of the LRA, the applicant describes its AMR of the containment spray system for license renewal. The process of identifying the aging effects is summarized in Appendix C to the LRA, and descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment spray system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.2, Table 3.2-2, and the applicable sections in Appendix C of the LRA. The staff determined that additional information was needed to complete its review.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

In Table 3.2-2 of the LRA, the applicant states that stainless steel and glass in a sodium hydroxide environment were determined to have no aging effects requiring management. In RAI 3.2-1, the staff requested the applicant to justify its conclusion that no aging effects were associated with stainless steel and glass in an environment of hydrazine or sodium hydroxide.

In its response, L-2002-157, dated September 26, 2002, the applicant cited the *Metals Handbook*, 9th Edition, Volume 13, and *The National Association of Corrosion Engineers Corrosion Data Survey*, 5th Edition, as references. The applicant states that the *Metals Handbook* shows a negligible corrosion rate (i.e., less than 0.1 mils/year) for stainless steel in the sodium hydroxide environment applicable to St. Lucie Unit 1 containment spray components (i.e., 28.5–30.5 percent by weight solution sodium hydroxide and maximum temperature of 100 °F). Additionally, the potential for SCC in a sodium hydroxide environment is avoided by maintaining temperatures below 200 °F. The applicant states that because the operating temperature of the components exposed to the sodium hydroxide internal environment is a maximum of 100 °F, there are no aging effects requiring management for these components. Similarly, the applicant states that based on the *National Association of Corrosion Engineers Corrosion Data Survey*, the corrosion rate is negligible for stainless steel in the hydrazine environment applicable to St. Lucie Unit 2 containment spray components (i.e., 25.4 percent by weight solution hydrazine and normal operating temperature of less than 100 °F). The applicant also states that these conclusions are supported by plant-specific operating experience, in that neither stainless steel nor glass in the environments of hydrazine or sodium hydroxide have experienced any adverse aging effects.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily revolves this issue because the applicant has provided sufficient evidence to demonstrate that stainless steel and glass are not subject to significant aging degradation in an environment of either hydrazine or sodium hydroxide.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the containment spray system SSCs to the environments described in Section 2.3.2.2 and Table 3.2-2 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments described.

3.2.2.2.2 Aging Management Programs

In Table 3.2-2 of the LRA, the applicant credits the following AMPs for managing the aging effects in the containment spray system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program
- ASME Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection Program

The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material for the Unit 1 aluminum refueling water tank exposed to a treated water—borated environment and for the Unit 1 cast iron containment spray pump cooler shells and the brass containment spray pump cooler flex connectors exposed to a treated water—other environment..

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be used to manage cracking and delamination for the portion of the Unit 1 refueling water tank made of fiberglass-reinforced vinyl ester exposed to a treated water—borated environment. The Chemistry Control Program will be used to manage loss of material for the stainless steel containment spray pumps, Unit 2 refueling water tank, eductors, Unit 1 aluminum refueling water tank vortex breaker, stainless steel orifices, and the stainless steel refueling water tank strainers, all of which are exposed to a treated water—borated environment.

The Chemistry Control Program will be used to manage loss of material and fouling for the Unit 1 stainless steel containment spray pump cooler tubes exposed to either treated water—borated (inside diameter) or treated water—other (outside diameter) environment. The Chemistry Control Program will also be used to manage loss of material and cracking for the stainless steel valves, piping/fittings, tubing/fittings, and thermowells exposed to a treated water—borated environments.

The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material for the Unit 1 aluminum refueling water tank exposed to an outdoor environment. The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material and cracking for the stainless steel piping/fittings exposed to an outdoor (ECCS pipe tunnel) environment. The Systems and Structures Monitoring Program will be used to manage loss of material for the Unit 1 cast iron containment spray pump cooler shells and the Unit 1 sight glass (carbon steel) exposed to an indoor not-air-conditioned environment. In addition, the Boric Acid Wastage Surveillance Program will be used to manage loss of material for the Unit 1 cast iron containment spray pump cooler shells and Unit 1 sight glass (carbon steel) exposed to borated water leaks.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-2, the staff concludes that the AMPs identified above will effectively manage the aging effects of the containment spray system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3 Conclusions

The staff has reviewed the information in Section 2.3.2.2 and Table 3.2-2 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment spray system will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment spray system, as required by 10 CFR 54.21(d).

3.2.3 Containment Isolation System

3.2.3.1 Summary of Technical Information in the Application

In Section 2.3.2.3 of the LRA, the applicant describes the containment isolation system as being designed to provide for the closure or integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment. The AMR results included are for those process systems whose only license renewal system intended function is containment isolation. Process systems that have license renewal system intended functions, in addition to the containment isolation function, are included in the system AMR results described elsewhere in Sections 3.1, 3.2, 3.3, and 3.4 of the LRA. The pressure boundary (metallic) portions of electrical penetrations and miscellaneous/spare mechanical penetrations that are not associated with a process system are included in the civil/structural AMR results described in Section 3.5. The nonmetallic and conductor portions of containment electrical penetrations are included in the electrical system AMR results described in Section 3.6 of the LRA. It is noted that an AMR was performed for all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described. Therefore, included in this evaluation are containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief. The containment vacuum relief is an exception because its additional function is to protect the containment vessels from subatmospheric internal pressure conditions created by a containment overcooling event.

Containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief components within the scope of license renewal and subject to AMR include valves (pressure boundary only), piping, tubing, fittings, and debris screens. The intended functions of containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief components subject to an AMR include pressure boundary integrity and filtration. A complete list of containment isolation components requiring an AMR, the component intended functions, and the applicable AMPs is provided in Table 3.2-3 of the LRA.

3.2.3.1.1 Aging Effects

In Table 3.2-3 of the LRA, the applicant identifies carbon steel, stainless steel, and brass as the materials of construction for the containment isolation system components. Loss of material was identified as an applicable aging effect for carbon steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel and brass materials are designed to be corrosion resistant in both dry and moist environments and, therefore, are not susceptible to loss of material in this environment. The air/gas environment is a compressed dry gaseous environment. Loss of material and cracking generally have not been a problem for carbon steel and brass surfaces that are exposed to air/gas environments. Based on the above, no aging effects were identified for the valves and piping/fittings (carbon steel), valves and tubing/fittings (stainless steel), Unit 1 debris screens (stainless steel), Unit 2 debris screens (carbon steel), and valves (brass) in air/gas environments. No aging effects were identified for the stainless steel tubing/fittings and Unit 1 debris screens exposed to the containment air. No aging effects were identified for the stainless steel valves and piping/fittings, tubing/fittings, and brass valves exposed to an environment of either indoor not-air-conditioned or containment air.

Loss of material of carbon steel materials by corrosion may occur in moist air environments, as well as in a borated water leaks environment. The applicant identified the aging effect of loss material for the carbon steel valves, piping/fittings, and debris screen exposed to the environments of indoor not-air-conditioned, containment air, or borated water leaks. In addition, loss of mechanical closure integrity was identified as an effect of aging for the carbon steel mechanical closure bolting exposed to a borated water leaks environment.

3.2.3.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment isolation system.

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Description of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the containment isolation system will be adequately managed by these AMPs for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.2 Staff Evaluation

In Section 2.3.2.3, Section 3.2, and Table 3.2-3 of the LRA, the applicant describes its AMR of the containment isolation system for license renewal. The process of identifying of the aging effects is summarized in Appendix C to the LRA, and descriptions of the AMPs are provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment isolation system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.3, Table 3.2-3, and the applicable sections in Appendix C to the LRA. The staff determined that additional information was needed to complete its review.

In its review of the aging effects for carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment isolation system SSCs to the environments described in Section 2.3.2.3 and Table 3.2-3 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments described.

3.2.3.2.2 Aging Management Programs

In Table 3.2-3 of the LRA, the applicant credits the following AMPs for managing the aging effects in the containment isolation system.

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Systems and Structures Monitoring Program will be used to manage loss of material for the carbon steel valves and piping/fittings exposed to an environment of either indoor not-air-conditioned or containment air. The Systems and Structures Monitoring Program will also be used to manage loss of material for the carbon steel debris screen exposed to a containment air environment. The Boric Acid Wastage Surveillance Program will be used to manage loss of material for the valves, piping/fittings, and debris screen (all made of carbon steel), as well as loss of mechanical closure integrity for the carbon steel bolting, exposed to a borated water leaks environment.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-3, the staff concludes that the AMPs identified above will effectively manage the aging effects of the containment isolation system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.3 Conclusions

The staff has reviewed the information in Section 2.3.2.3 and Table 3.2-3 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment isolation system will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment isolation system, as required by 10 CFR 54.21(d).

3.2.4 Safety Injection System

3.2.4.1 Summary of Technical Information in the Application

In Section 2.3.2.4 of the LRA, the applicant describes the safety injection system as being designed to provide emergency core cooling and reactivity control during and following DBEs. Portions of the safety injection system are also used for shutdown cooling functions. In addition, some portions of the safety injection system, including the shutdown cooling heat exchangers, are used in conjunction with containment spray to cool the containment.

Safety injection system components subject to an AMR include safety injection tanks, pumps and valves (pressure boundary only), heat exchangers, orifices, thermowells, piping, tubing, and fittings. The intended functions of safety injection components subject to an AMR include pressure boundary integrity, heat transfer, and throttling. A complete list of safety injection components requiring an AMR and the component intended functions is provided in Table 3.2-4 of the LRA.

3.2.4.1.1 Aging Effects

In Table 3.2-4 of the LRA, the applicant identifies stainless steel, carbon steel clad with stainless steel, carbon steel, cast iron, and brass as the materials of construction for the safety injection components. Loss of material was identified as an applicable aging effect for stainless steel, carbon steel clad with stainless steel, carbon steel, cast iron, and brass. Cracking was identified as an applicable aging effect for stainless steel and carbon steel clad with stainless steel. Fouling was identified as an applicable aging effect for stainless steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building environments. No aging effects were identified for the safety injection tank, valves, piping/fittings, tubing/fittings, orifices, and bolting, which are all made of stainless steel, in air/gas, indoor not-air-conditioned, or containment environments. No aging effects were identified for the stainless steel thermowells and high- and low-pressure safety injection pumps in indoor not-air-conditioned environments.

Loss of material and cracking of stainless steel materials in a treated water environment are possible aging effects under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low-flow conditions could lead to loss of material and cracking of stainless steel in treated water. The applicant identified the aging effect of loss of material for the stainless steel high-pressure safety injection (HPSI) pumps exposed to treated water—borated environments. Loss of material and cracking were identified as aging effects for the stainless steel safety injection tanks, low-pressure safety injection (LPSI) pumps, shutdown cooling heat exchanger channel nozzles, channel facings, channel cover facings, valves, piping/fittings, thermowells, tubing/fittings, and orifices exposed to a treated water—borated environment.

For stainless steel heat exchanger tubes or pump cooler tubes exposed to treated water environments, the tubes may be susceptible to fouling which, if unattended, has the potential to block the flow of coolant through the tubes and, in some cases, to produce corrosive environments that could lead to a loss of tube material. The applicant identified the aging effects of loss of material and fouling for the stainless steel shutdown cooling heat exchanger tubes, Unit 1 LPSI pump cooler tubes, and HPSI pump cooler tubes exposed to a treated water—borated or treated water—other environment. Based on the same reasoning, the applicant identified the aging effects of loss of material, fouling, and cracking for the shutdown cooling heat exchanger tubes and Unit 1 LPSI pump cooler tubes exposed to treated water—borated environments. The applicant also identified the aging effects of loss of material and cracking for the shutdown cooling heat exchanger tube sheets, which are made of carbon steel clad with stainless steel, exposed to treated water—borated environments. Similarly, the applicant identified loss of material for the same shutdown cooling heat exchanger tube sheets exposed to treated water—other environments.

Loss of material of carbon steel and cast iron materials through general corrosion may occur when in contact with treated water environments. The applicant identified the aging effect of loss of material for the carbon steel shutdown cooling heat exchanger shells, baffles, and tube supports; Unit 2 carbon steel HPSI pump cooler shells; and Unit 1 cast iron LPSI and HPSI pump cooler shells, all of which are exposed to treated water—other environments. Similarly, the applicant identified the aging effect of loss of material for the Unit 1 brass HPSI pump cooler tube shields. Loss of material of carbon steel and cast iron materials by corrosion may occur in moist air environments (e.g., ventilated, sheltered, or reactor building). The applicant identified the aging effect of loss of material for the carbon steel shutdown cooling heat exchanger shells, shutdown cooling heat exchanger channel heads and channel covers, Unit 2 HPSI pump cooler shells, and Unit 1 cast iron HPSI and LPSI pumps cooler shells exposed to an indoor not-air-conditioned or borated water leaks environment. In addition, loss of mechanical closure integrity was identified with the carbon steel mechanical closure bolting exposed to a borated water leaks environment.

3.2.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the safety injection system.

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the safety injection system will be adequately managed by these AMPs for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.4.2 Staff Evaluation

In Section 2.3.2.4, Section 3.2, and Table 3.2-4 of the LRA, the applicant describes its AMR of the safety injection system for license renewal. The process of identifying of the aging effects is summarized in Appendix C of the LRA, and descriptions of the AMPs are provided in

Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the safety injection system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.4, Table 3.2-4, and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the safety injection system SSCs with the environments described in Section 2.3.2.4 and Table 3.2-4 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments described.

3.2.4.2.2 Aging Management Programs

In Table 3.2-4 of the LRA, the applicant credits the following AMPs for managing the aging effects in the safety injection system.

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program will be used to manage loss of material, cracking, or fouling for all the stainless steel components exposed to a treated water—borated or treated water—other environment. The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material for the components made of carbon steel, cast iron, and brass exposed to a treated water—other environment. The Systems and Structures Monitoring Program will be used to manage loss of material for the carbon steel and cast iron components exposed to an indoor not-air-conditioned environment. The Boric Acid Wastage Surveillance Program will be used to manage loss of material for the carbon steel and cast iron components exposed to a borated water leaks environment. Finally, the Boric Acid Wastage Surveillance Program will be used to manage loss of mechanical closure integrity for the carbon steel bolting exposed to a borated water leaks environment.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-4, the staff concludes that the AMPs identified above will effectively manage the aging effects of the safety injection system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.3 Conclusions

The staff has reviewed the information in Section 2.3.2.4 and Table 3.2-4 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the safety injection system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the safety injection system, as required by 10 CFR 54.21(d).

3.2.5 Containment Post-Accident Monitoring

3.2.5.1 Summary of Technical Information in the Application

In Section 2.3.2.5 of the LRA, the applicant states that the following subsystems are included in the containment post-accident monitoring system.

- containment hydrogen monitoring
- post-accident sampling (Unit 2 only)
- containment atmosphere radiation monitoring

Containment hydrogen monitoring indicates the hydrogen gas concentration in the containment atmosphere following a loss-of-coolant accident (LOCA). The mechanical portions of this subsystem provide a flow path from the containment to the hydrogen analyzers and then back to the containment. The only mechanical portion of the post-accident sampling subsystem (Unit 2 only) in the scope of license renewal us the valves that provide a pressure boundary for containment hydrogen monitoring. Containment atmosphere radiation monitoring measures radioactivity in the containment air. The mechanical portions of containment atmosphere radiation monitoring provide a flow path from the containment to the monitors and then back to the containment.

Containment post-accident monitoring components subject to an AMR include valves (pressure boundary only), sample vessel, flexible hoses, piping, tubing, and fittings. The intended function of containment post-accident monitoring components subject to an AMR is pressure boundary integrity. A complete list of the containment post-accident monitoring components requiring an AMR, the component intended functions, and the applicable AMPs is provided in Table 3.2-5 of the LRA.

3.2.5.1.1 Aging Effects

In Table 3.2-5 of the LRA, the applicant identifies stainless steel and carbon steel as the materials of construction for the containment post-accident monitoring components. Loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting exposed to a borated water leaks environment.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building environments. No aging effects were identified for the stainless steel flex hoses, valves, sample vessels (Unit 1), or tubing/fittings in either an air/gas, containment air, or indoor not-air-conditioned environment.

Loss of material of carbon steel materials may occur in a borated water environment or in the event of borated water leaks from other plant systems. Loss of mechanical closure integrity was identified with carbon steel mechanical closure bolting exposed to borated water leaks.

3.2.5.1.2 Aging Management Programs

The Boric Acid Wastage Surveillance Program is utilized to manage aging effects in the containment post-accident monitoring system. A description of this AMP is provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the containment post-accident monitoring system will be adequately managed by this AMP for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2 Staff Evaluation

In Section 2.3.2.5, Section 3.2, and Table 3.2-5 of the LRA, the applicant describes its AMR of the containment post-accident monitoring system for license renewal. The process of identifying the aging effect is summarized in Appendix C to the LRA, and a descriptions of the AMP provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment post-accident monitoring system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.5, Table 3.2-5, and the applicable sections in Appendix C of the LRA. The staff determined that additional information was needed.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment post-accident monitoring system SSCs with the environments described in Section 2.3.2.5 and Table 3.2-5 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments described.

3.2.5.2.2 Aging Management Programs

In Table 3.2-5 of the LRA, the applicant credits the Boric Acid Wastage Surveillance Program for managing the aging effects in the containment post-accident monitoring system.

The Boric Acid Wastage Surveillance Program will be used to manage loss of mechanical closure integrity for the carbon steel bolting exposed to a borated water leaks environment. This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-5, the staff concludes that the AMP identified above will effectively manage the aging effects of the containment post-accident monitoring system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.3 Conclusions

The staff has reviewed the information in Section 2.3.2.5 and Table 3.2-5 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment post-accident monitoring system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment post-accident monitoring system, as required by 10 CFR 54.21(d).

3.3 Auxiliary Systems

In Section 3.3, "Auxiliary Systems," of the LRA, the applicant describes the AMR for the auxiliary systems. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the auxiliary systems. The staff reviewed Section 3.3 and the applicable portions of Appendices A, B, and C to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3), for the auxiliary system SCs that are determined to be within the scope of license renewal and subject to an AMR.

The St. Lucie auxiliary systems include the following 16 systems.

(1) chemical and volume control
(2) component cooling water
(3) demineralized makeup water (Unit 2 only)
(4) diesel generators and support systems
(5) emergency cooling canal
(6) fire protection

(7) fuel pool cooling
(8) instrument air
(9) intake cooling water
(10) miscellaneous bulk gas supply
(11) primary makeup water
(12) sampling
(13) service water
(14) turbine cooling water (Unit 1 only)
(15) ventilation
(16) waste management

In Subsection 2.3.3 of the LRA, the applicant provides a description of these systems and identifies the components requiring AMRs. The staff's evaluations of the scoping methodology and the auxiliary systems' SCs included within the scope of license renewal and subject to an AMR are documented in Sections 2.1 and 2.3.3, respectively, of this SER. In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required by 10 CFR 54.21(d). In Appendix B to the LRA, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In Appendix C to the LRA, the applicant describes the processes used to identify many of the applicable aging effects for the SCs that are subject to an AMR. In Appendix D to the LRA, the applicant states that no changes to the St. Lucie Technical Specification have been identified. A review of each of the auxiliary systems follows.

3.3.0 Aging Management Programs

3.3.0.1 Chemistry Control Program—Fuel Oil Chemistry Subprogram

The applicant describes its Fuel Oil Chemistry subprogram in Section B.3.2.5.3 of the LRA. This section addresses the procedures for controlling the fuel oil chemistry in order to ensure its compatibility with the materials of construction of the components exposed to the fuel oil environment. The staff reviewed Section B.3.2.5.3 of the LRA to determine whether the applicant has demonstrated that the Fuel Oil Chemistry subprogram will adequately manage the applicable aging effects for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.0.1.1 Summary of Technical Information in the Application

In Section 3.2.5.3 of Appendix B of the LRA, the applicant states that the Fuel Oil Chemistry Subprogram is a plant-specific program that was developed in accordance with the guidance of ASTM D975-81. The program has been an ongoing program at St. Lucie since the initial start up and has evolved over many years of plant operation. The applicant states that the AMP XI.M30, "Fuel Oil Chemistry," in the GALL Report contains additional aspects such as water removal and internal tank inspection. The applicant also states that aging effects will be managed by the Fuel Oil Chemistry subprogram to ensure that significant degradation is not occurring and that component intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant provides the methods for controlling fuel oil quality in order to ensure that it is compatible with the materials of construction of the components exposed to fuel oil. Use of contaminated fuel oil could lead either to corrosion damage of storage tanks or to accumulation of particulate or biological growth that would interfere with the operation of safety-related equipment. In the Fuel Oil Chemistry Subprogram, the applicant specified fuel oil analyses, minimum sampling frequencies, and acceptance criteria needed for maintaining the required fuel oil quality. The acceptance criteria for these tests are based, to a great extent, on the ASTM standards listed in the LRA. Also, the applicant identified corrective actions that would be taken if the fuel oil did not meet the prescribed specifications.

3.3.0.1.2 Staff Evaluation

The staff's evaluation of the Fuel Oil Chemistry Subprogram focused on how the program manages aging effects through the effective incorporation of the following 10 elements—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these program attributes is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The scope of the Fuel Oil Chemistry Subprogram is focused on managing the conditions that may cause loss of material of diesel fuel oil system component internal surfaces. The subprogram serves to reduce the potential of exposure of the internal surfaces to fuel oil contaminated with water and microbiological organisms. The staff found the program scope acceptable because the aging effects specified can be managed by the program discussed in the LRA.

Preventive Actions: Maintaining proper fuel oil chemistry through regular inspections for the presence of water, particulate, and other contaminants, and taking appropriate corrective actions, will prevent the degradation of the components in the systems containing fuel oil. Periodic cleaning of the DOSTs tanks and periodic draining of water collected at the bottom of the tanks minimizes the amount of water and the length of contact time.

In this attribute, the applicant stated that tank inspection and water removal are performed as part of the Periodic Surveillance and Preventive maintenance program. Corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom. Ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring. By letter dated July 18, 2002, the staff requested, in RAI B.3.2.5-3, the applicant to provide additional information concerning the identification of the locations in the fuel oil components (e.g., fuel oil tank bottoms) at which periodic fuel oil samples are obtained. The staff further requested the applicant to indicate when thickness measurements are used to detect aging effects on the tank bottom.

In its response dated September 26, 2002, the applicant stated that degradation of the tank bottoms due to accumulation of contaminants has not been experienced at St. Lucie. In order to ensure that contaminants are not accumulating and causing degradation of the diesel fuel oil components, the diesel fuel oil quality is managed by the Chemistry Control Program—Fuel Oil Chemistry Subprogram. This program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces and the emergency diesel generator (EDG) fuel supply system.

To ensure purity of the fuel throughout the system, upon receipt of new fuel oil and prior to transferring the oil from the tanker to the storage tanks, fuel is tested to specific ASTM standards, verifying proper American Petroleum Institute (API) gravity, kinematic viscosity, flash point, appearance, and color. In addition, fuel in the storage tanks are sampled and tested at least once every 31 days in accordance with ASTM D2276-83 and by verifying total particulate contamination of less than 10 mg/liter. Prior to obtaining storage tank samples, the tanks are placed on recirculation to ensure that the samples are representative of the bulk fuel oil in the tanks.

Accumulated water is also removed from both of the storage tanks as required by the St. Lucie Technical Specifications. Accumulated water from the bottom of the tanks is removed at least once every 92 days. In addition to the removal of water accumulation per St. Lucie Technical Specification requirements, the storage tanks are drained, cleaned of accumulated sediment, and visually inspected for internal corrosion every 10 years. Thickness measurements of the tank bottoms would only be taken if required as part of corrective actions to address significant loss of material under the Periodic Surveillance and Preventive Maintenance Program. To date, all of the tanks have been inspected with no indication of aging mechanisms or effects. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

On the basis of its review, the staff finds the response of the applicant reasonable and adequate because the procedures undertaken by the applicant ensure the purity of the fuel throughout the system and remove accumulated water from both the storage tanks as required by the St. Lucie Technical Specifications. In addition, the staff finds that these procedures are adequate because they include all the activities needed for maintaining the quality of fuel oil and managing the potential aging effects of the components in the systems containing fuel oil.

Parameters Monitored or Inspected: The Fuel Oil Chemistry Subprogram monitors fuel oil quality by performing a number of tests. Most of these tests follow the procedures specified in the ASTM standards. For determining water and sediment content, and for particulate testing in fuel oil, the applicant will follow the procedures described in ASTM D-1796 and ASTM D-2276, respectively. The staff finds that the procedures used by the applicant for monitoring fuel oil quality with regard to its effect on the components exposed to the fuel oil environment are based on well-established methods and the applicant's inspection program is, therefore, acceptable.

Detection of Aging Effects: The Fuel Oil Chemistry Subprogram is an activity which minimizes aging effects by controlling the fuel oil environment and taking appropriate corrective actions. It does not directly detect aging effects. The purpose of the program is to ensure that an optimum environment in the systems containing fuel oil exists and that no component degradation due to aging effects is occurring. The staff found this acceptable because the Fuel Oil Chemistry Subprogram is a preventive program and as such is not credited for detecting aging effects.

Monitoring and Trending: In the LRA, the applicant states that water and particulate contaminants are monitored and trended. The St. Lucie Technical Specifications require that sampling and analysis of fuel oil chemistry be performed monthly. The sampling and analysis will provide an opportunity to detect fuel oil conditions that can lead to fuel oil tank degradation so that appropriate corrective actions can be taken in a timely manner. In addition, the freshly delivered oil will be sampled for water and sediment content prior to its transfer to the supply tanks. The staff reviewed the applicant's monitoring and trending program and found that it will provide the applicant with an effective way of controlling fuel oil quality.

Acceptance Criteria: In the LRA, the applicant states that the acceptance criteria for the chemistry parameters required to be monitored and controlled are listed in the St. Lucie Technical Specifications and the procedures the Chemistry Control Program. Adherence to the criteria will ensure that the quality of fuel oil will be kept at an acceptable level and any departure from it will result in timely corrective action. The staff found the acceptance criteria for the Fuel Oil Chemistry Subprogram to be effective in controlling aging effects for the components and systems exposed to fuel oil because the criteria allow for early detection and corrective action of fuel oil chemistry deviations.

Operating Experience: In the LRA, the applicant states that the operating experience at St. Lucie Units 1 and 2 has included particulate contamination attributable to a contaminated tanker truck transfer pump and hose. The applicant further stated that no instances of fuel oil system component failures attributable to contamination have been identified. By letter dated July 18, 2002, the staff requested the applicant to provide additional information (RAI B 3.2.5-4) concerning the corrective action taken to prevent recurrence, and to discuss the operating experience regarding the effectiveness of the AMP such that aging degradation, which could lead to the loss of an intended function, will be identified and addressed before it results in age-related failures of the fuel oil system components.

In its response to the NRC dated September 26, 2002, the applicant stated that particulate contamination of the diesel fuel oil storage tanks was discovered when an offsite contract laboratory identified out-of-specification particulate contamination in three of the four DOSTs. This event was caused by the use of a contaminated fuel oil tanker truck transfer pump and hose. To prevent recurrence of contamination caused by the contaminated tanker truck transfer pump and hose, FPL ensured that: (1) the chemistry procedure was revised to require flushing the first 100 gallons of diesel fuel oil into drums to ensure cleanliness of the tanker, pump, and discharge hose; (2) a permanent filtration unit was installed at the site which is connected to the fuel oil tanker discharge hose to remove possible contamination after the initial 100-gallon flush; and (3) chemistry procedures were revised to correct deficiencies (e.g., use of incorrect solvent in the sampling process). In addition, St. Lucie diesel fuel oil analytical techniques were reviewed by an outside vendor to ensure compliance with ASTM standards.

The applicant also stated that to ensure that degradation of the diesel fuel oil tank and fuel supply system does not occur, exposure of the internal surfaces to contaminants in the fuel oil is minimized. This is accomplished by implementing the following AMPs for the diesel generator fuel oil system.

- The Chemistry Control Program—Fuel Oil Chemistry Subprogram provides for monitoring of fuel oil parameters in accordance with ASTM Standards (as specified in the St. Lucie Technical Specifications), addition of biocides to minimize biological activity, addition of stabilizers to prevent biological breakdown of the diesel fuel, and addition of corrosion inhibitors to mitigate corrosion.

- The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B, Subsection 3.2.11, page B-46) provides for the periodic removal of water from the fuel oil storage tanks and the draining and cleaning of the storage tanks every 10 years.

Furthermore, the applicant stated that, based on a review of St. Lucie plant-specific operating experience, with the exception of the particulate contamination described above, no instances of fuel oil component failures attributable to contamination have been identified. Visual inspection of the storage tanks has not identified any degradation due to corrosion or any other mechanism.

On the basis of its review, the staff finds the response of the applicant reasonable and adequate because both the corrective action undertaken by the applicant to prevent recurrence and the result of the review of plant-specific operating experience demonstrate the effectiveness of the AMP such that aging degradation will be identified and addressed before it results in age-related failures of the fuel oil system.

Operating experience with the systems covered by the Fuel Oil Chemistry Subprogram has demonstrated the effectiveness of the program. The program has been ongoing St. Lucie since the initial start up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations. The review of operating experience at St. Lucie showed that there had been no instances of fuel oil system component failures attributed to contamination. Tank inspections were performed in accordance with St. Lucie Technical Specifications. As a result of operating experience, the staff agrees that the applicant implemented an effective Fuel Oil Chemistry Subprogram, and that the program will effectively manage the applicable aging effects for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.0.1.3 UFSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 to the LRA provide the applicant's UFSAR supplement for the Chemistry Control Programs at St. Lucie. The program descriptions are consistent with the material contained in Section 3.2.5.3 of Appendix B and are therefore acceptable to the staff.

3.3.0.1.4 Conclusions

The staff has reviewed the information provided in Section 3.2.5.3 of Appendix B to the LRA, the applicant's responses to the staff's RAIs, and the summary description of the Chemistry Control Program in Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the UFSAR supplement. On the basis of this review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with the SCs of the Fuel Oil Chemistry Subprogram will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff concludes that the UFSAR supplement contains an appropriate summary description of the programs and activities for managing the effects of aging for the fuel oil systems, as required by 10 CFR 54.21(d).

3.3.0.2 Intake Cooling Water System Inspection Program

The Intake Cooling Water System Inspection Program is described in Section 3.2.10 of Appendix B to the LRA. The applicant credited this program for managing the aging of components in the intake cooling water system and the component cooling water system. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Intake Cooling Water System Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.0.2.1 Summary of Technical Information in the Application

The Intake Cooling Water Inspection Program is credited for aging management of specific component/commodity groups in the intake cooling water system and the component cooling water system. This program is plant-specific, although certain aspects of the Intake Cooling Water Inspection Program are comparable to GALL AMP XI.M20, "Open-Cycle Cooling Water System." The applicant credits the Intake Cooling Water System Inspection Program, the Systems and Structures Monitoring Program, the Periodic Surveillance and Preventive Maintenance Program, and the Boric Acid Wastage Surveillance Program for managing aging of intake cooling water and component cooling water components systems at St. Lucie Units 1 and 2.

The aging effects requiring management in the intake cooling water system are loss of material for carbon steel, stainless steel, cast iron, aluminum brass, aluminum bronze, bronze, and Monel components, and cracking for rubber and fiberglass components. The aging effects requiring management in the component cooling water system are loss of material for carbon steel, stainless steel, cast iron, and aluminum bronze components, and loss of material and fouling for aluminum brass components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

The Intake Cooling Water System Inspection Program addresses the aging effects of loss of material due to various corrosion mechanisms and biological and particulate fouling. It also addresses internal inspection of the intake cooling water piping to identify and manage loss of material on the external surface of buried piping. The program utilizes differential pressure performance evaluations, systematic inspections, and corrective actions to ensure that loss of material or fouling does not lead to loss of intended function of license renewal components. NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," requires the implementation of an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage caused by biological fouling, particulate fouling, corrosion, protective coating failures, and silting problems in systems and components supplied with intake cooling water. The Intake Cooling Water System Inspection Program scope, method, and testing frequencies are in accordance with the commitments made by the applicant under GL 89-13.

3.3.0.2.2 Staff Evaluation

The staff evaluated the program against the 10 program attributes described in Appendix A to NUREG—1800 program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Intake Cooling Water Inspection Program is credited for aging management of specific components/commodity groups in the intake cooling water system and the component cooling water system. Section 3 of the LRA indicates that the program is credited for strainers, valves, piping, fittings, and orifices in the intake cooling water system, and heat exchanger components in the component cooling water system. The program addresses the aging effects of loss of material due to various corrosion mechanisms and biological and particulate fouling. It also addresses internal inspection of the intake cooling water piping to identify and manage loss of material on the external surface of buried piping. The staff finds the program scope to be acceptable because the aging effects specified can be managed by the program discussed in the LRA.

Preventive Actions: The LRA states that the Intake Cooling Water Systems Inspection Program is preventive in nature since it provides for the periodic inspection and maintenance of internal linings and coatings of piping and components exposed to aggressive cooling water environments. The program employs performance monitoring, testing, and periodic inspection and cleaning of heat exchangers, nondestructive examination of heat exchanger tubes, and backflushing and inspection of the intake cooling water strainers. While external coatings are applied to portions of the intake cooling water system to minimize corrosion, coatings are not credited in the determination of aging effects requiring management.

The UFSAR for Unit 1 states that the component cooling water heat exchanger components exposed to raw water are protected by sacrificial anodes located in the heat exchangers. The applicant did not provide any information about inspection or replacement of these anodes. Therefore, the staff issued RAI B.3.2.10-4 requesting information about whether these sacrificial anodes are credited in preventing or mitigating loss of material due to corrosion of the heat exchanger components exposed to raw water. The staff also asked the applicant to identify and describe the program that provides for inspection of these anodes. By letter dated September 26, 2002, the applicant stated that each of the Unit 1 CCW heat exchangers has sacrificial anodes installed as a preventive measure to minimize the potential for corrosion of parts exposed to raw water; however, the anodes are not credited with reducing the loss of material. The staff had also issued RAI 3.3.2-3, asking whether the CCW head exchanger tubes were subject to cracking, as had been found in similar heat exchanger tubes and conditions at Turkey Point Units 3 and 4. In its September 26, 2002, response to RAI 3.3.2-3, the applicant stated that the St. Lucie CCW heat exchanger tubes were not subject to cracking because, unlike Turkey Point, St. Lucie had not installed a chemical injection system like that used at Turkey Point, and St. Lucie CCW heat exchangers had sacrificial anodes. From these two responses, it was not clear to the staff whether the applicant had credited the sacrificial anodes for preventing cracking of the tubes and, if so, whether the applicant had a sufficient program in place to inspect and replace the anodes. By letter dated November 27, 2002, the applicant clarified that the anodes are not credited for the prevention of cracking in the CCW heat exchanger tubes. Therefore, the staff finds it acceptable that the anodes are not covered by this program.

Based on the above, the staff finds the applicant's preventive actions adequate and acceptable because the performance monitoring, testing, and periodic cleaning of heat exchangers and the backflushing of the system will mitigate the aging effects. The staff also notes the preventive measures of coatings and sacrificial anodes, although these are not credited for license renewal.

Parameters Monitored or Inspected: The LRA states that surface conditions of piping/components and their internal linings are visually inspected for degradation. Wall thickness measurements are taken when deemed necessary. Pressures, temperatures, and flows associated with the CCW heat exchangers are monitored during normal operation to verify heat transfer capability. Tube integrity of CCW heat exchangers is monitored by periodic nondestructive examinations to ensure early detection of aging effects. The staff finds the proposed measures reasonable and acceptable because visual inspections, wall thickness measurements, and monitoring of pressures, temperatures, and flow will permit timely detection of the aging effects.

Detection of Aging Effects: The LRA states that visual inspections of piping/components are performed to identify loss of material, fouling, damaged linings, and degraded material condition. Volumetric testing may be utilized to measure internal and external surface conditions and the extent of wall thinning based on the evaluation of the examination results. Monitoring of the CCW heat exchangers is conducted to provide early identification of fouling and degraded conditions that could impact the ability of the CCW heat exchangers to perform their intended function. Periodic tube inspections and cleaning are performed to assure heat exchanger performance and integrity. The staff finds the applicant's techniques for the detection of aging effects adequate and acceptable because the proposed visual inspections and volumetric testing methods are consistent with industry practice and experience.

Monitoring and Trending: The LRA states that the inspection scope, method, and testing frequencies are in accordance with the applicant's commitments under GL 89-13. Internal inspections of the intake cooling water piping and components are normally performed during refueling outages on a scope and frequency based on past inspection results. As-found conditions are documented, and repairs are made as required. Monitoring of system parameters is used to provide an indication of flow blockage. CCW heat exchanger tube condition is determined by eddy current testing and is documented accordingly. Heat exchanger tube cleaning, tube replacement, or other corrective actions are implemented as required.

In RAI B.3.2.10-1, the staff asked the applicant to provide the inspection frequencies, bases, and the most recent operating history supporting the adequacy of this program for components in the intake cooling water system in stainless steel, carbon steel, and cast iron intake cooling water pumps; rubber intake cooling water pump expansion joints; and aluminum-bronze pump discharge valves exposed externally to a raw water environment. The LRA had provided this information for other components in the intake cooling water system. By letter dated September 26, 2002, the applicant provided the following response.

> As indicated on LRA Table 3.3-9 (pages 3.3-59 and 3.3-62), St. Lucie has no cast iron or carbon steel intake cooling water (ICW) pumps. The pump casings are made of stainless steel or aluminum bronze. The current frequency of inspection for the ICW pumps is 96 months. This frequency is appropriate based on the operating and maintenance history of these components at St. Lucie. The current frequency of replacement of the Unit 1 ICW pump expansion joints is 120 months. This frequency was also determined to be acceptable based upon past experience. The frequency of these inspections may be adjusted as necessary based on future plant-specific performance and/or industry experience. The Unit 2 ICW pump expansion joints are constructed of stainless steel.
>
> Other than vent, drain, and instrument valves, there are no aluminum bronze valves in ICW, and none are exposed externally to a raw water environment.

The staff finds the applicant's response to be acceptable and the issues related to RAI B.3.2.10-1 resolved because none of the vulnerable components are exposed to a raw water environment.

In RAI B.3.2.10-3, the staff asked the applicant to identify the plant procedures and applicable documents that contain detailed guidance related to performance monitoring testing and tube examinations of heat exchangers. By letter dated September 26, 2002, the applicant provided the names of the procedures and stated that the procedures contain CCW heat exchanger performance monitoring acceptance criteria that ensure that design-basis and technical specification requirements for heat transfer capability are maintained. The applicant also stated that guidelines are provided for cleaning, inspecting, and testing the heat exchangers. The staff finds that monitoring to ensure that design-basis and technical specification requirements for heat transfer capability are maintained is acceptable.

In RAI B.3.2.10-5, the staff asked the applicant to identify the criteria used to determine which components should be inspected. By letter dated September 26, 2002, the applicant stated that the internal inspections of intake cooling water piping and components are normally performed during the refueling outages on a scope and frequency based on past inspection results. The current inspection covers 100 percent of the internally accessible components (including linings of fittings such as elbows) and is performed on an every other refueling interval. Based on St. Lucie plant-specific operating experience, this inspection scope and frequency are adequate to ensure that ICW piping will continue to perform its intended function for the period of extended operation. The applicant stated that the frequency of the inspections may be adjusted as necessary based on inspection results and industry experience. The staff finds that adjusting the scope and frequency based on operating experience is acceptable, and the current scope of inspections appears reasonable.

The staff finds that the proposed methodologies will provide effective monitoring and trending of aging effects and are therefore acceptable.

Acceptance Criteria: The LRA stated that visual examinations of the internal surface of piping, fittings, heat exchangers, and basket strainers are performed to identify loss of material. When required, determination of wall thickness values is performed and evaluated. The LRA also states that monitoring heat exchanger differential pressure, flow, and temperatures during normal operation ensures that the design-basis heat transfer capability is maintained. Periodic backflushing removes the accumulation of biofouling agents, corrosion products, and silt. Biological and particulate materials not removed by backflushing are removed when the system is opened for cleaning and inspection.

As described above, performance monitoring acceptance criteria for the CCW heat exchanger ensure that design-basis and technical specification requirements for heat transfer capability are maintained. In addition, wall thickness values are determined and wall thickness is evaluated, as required. The staff finds that using acceptance criteria that ensure that the design-basis and technical specification requirements are maintained is acceptable.

Operating Experience: The LRA states the following—

> The existing Intake Cooling Water System Inspection Program has been an ongoing formalized inspection program at St. Lucie since 1990. The program was formally implemented as a result of Generic Letter 89-13, which documented the need to implement monitoring of service water systems to ensure that they would perform their safety-related function. The conservative philosophy established within the program has been successful in managing the loss of material due to corrosion and fouling of the Component Cooling Water heat exchangers. Various sections of the Intake Cooling Water piping, basket strainers, and heat exchangers are periodically examined using visual examination to determine the effects of corrosion and fouling. Results are evaluated and components are either repaired or replaced as required. Branch connections are

examined as plant/industry experience warrants.

Metallurgical analyses of Component Cooling Water heat exchanger tubes, performed in 1988 and 1991, indicated that erosion of aluminum brass tubes was caused by shells lodged in the tubes. Localized erosion caused small pinhole leaks in the tubes. To preclude erosion from occurring, the Component Cooling Water heat exchangers are opened periodically for cleaning and inspection.

A review of operating history for Intake Cooling Water and Component Cooling Water shows that the current aging management programs have supported system availability above its performance criteria for the period from May 1996 through June 2001. In addition, there have been no functional failures attributed to aging of pressure-retaining components during that period.

On page B-45 of Appendix B to the LRA, the applicant states that the Intake Cooling Water System Inspection Program includes examination of the ICW branch connections as warranted by plant and industry experience. Since this is an existing program, the staff issued RAI 3.3.2-5 requesting that the applicant describe the findings of past examinations and discuss which aging effect(s), if any, has been observed at the branch connections. The applicant was also asked to include the root cause of any identified aging effects. In its response dated September 26, 2002, the applicant stated that the past inspections of ICW piping have identified susceptibility to loss of material due to corrosion resulting from localized internal and external coating failures on branch lines. The applicant added that small branch lines may not have an internal lining/coating based upon size, and some consist of stainless steel instrumentation tubing. The applicant further stated that accessible portions of branch connections, which typically constitute vents, drains, and instrumentation lines, are examined internally during the main header crawl-through inspections, and all smallbore lines are inspected externally. The applicant provided several examples of the findings of past inspections of branch connections. The examples included loss of material due to corrosion, leading to through-wall leaks in some cases. The staff finds the RAI response acceptable because the applicant described the findings of past examinations, along with root causes, as requested.

The staff discussed the operating history at length with the applicant during public meetings. The staff finds that the operating experience supports the applicant's conclusion that the Intake Cooling Water System Inspection Program provides reasonable assurance that the aging of systems and components within the scope of the program will be adequately managed, as required by 10 CFR 54.21(a)(3).

3.3.0.2.3 UFSAR Supplement

The staff has reviewed the summary description of the Intake Cooling Water System Inspection Program in the UFSAR supplement in Appendix A to the LRA. The staff concluded that the UFSAR supplements contain the essential elements of the program and, therefore, provide an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.3.0.2.4 Conclusions

The staff has reviewed the information provided in Section 3.2.10 of Appendix B to the LRA, the applicant's September 26, 2002, response to the staff's RAIs, the applicant's November 27, 2002, letter providing supplements to its September 26, 2002, letter, and the summary description of the Intake Cooling Water System Inspection Program in Appendix A to the LRA.

On the basis of this review and the above evaluation, the staff finds that the Intake Cooling Water System Inspection Program will adequately manage the aging effects so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1 Chemical and Volume Control

3.3.1.1 Summary of Technical Information in the Application

The chemical and volume control system (CVCS) provides a continuous feed and bleed for the RCS to maintain proper water level and to adjust boron concentration. At St. Lucie, the CVCS consists of a charging subsystem, a letdown subsystem, and a boric acid makeup subsystem. Details of the CVCS are described in Section 9.3.4 of the UFSARs for Units 1 and 2.

3.3.1.1.1 Aging Effects

Components of the CVCS are described in Section 2.3.3.1 of the LRA as being within the scope of license renewal and subject to an AMR. Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), housings, tanks, heat exchangers, strainers, orifices, thermowells, piping, tubing and fittings, and bolting. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of treated water (borated and other). Exposure of stainless steel to either outdoor, air-gas, indoor not-air-conditioned, or containment air environments has no aging effects. One exception is that previously heat- traced stainless steel piping and fittings components exposed to an indoor not-air conditioned environment are identified as being subject to cracking. Another exception is that stainless steel components located in the ECCS pipe tunnel (outdoor environment) are identified as being subject to SCC and loss of material. Carbon steel bolting is identified as being subject to loss of mechanical closure integrity from the borated water leak environment, and as having no aging effect from exposure to the outdoor, indoor not-air-conditioned, or containment air environments. For St. Lucie Units 1 and 2, fatigue of regenerative heat exchangers, letdown heat exchangers, valves, piping, and fittings is identified as a TLAA and is addressed in Section 4.3.2 of the LRA.

3.3.1.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the CVCS.

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the CVCS will be adequately managed by these AMPs for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.2 Staff Evaluation

The applicant described its AMR of the CVCS for license renewal in Section 2.3.3.1 and Section 3.3, Table 3.3-1, pages 3.3-13 through 3.3-17 of the LRA. The process of identifying of the aging effects is summarized in Appendix C to the LRA, and a descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the CVCS will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.1, Table 3.3-1, pages 3.3-13 through 3.3-17, and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

In Table 3.3-1 of the LRA, the applicant identified the air/gas environment as an applicable internal environment for the stainless steel boric acid makeup tanks, volume control tanks, valves, piping/fittings, and tubing/fittings. The applicant did not identify any aging effects of these components in the air/gas environment. The aging effects associated with exposure to the air/gas environment are identified in Table 3.3-1 and are discussed in Section 5 of Appendix C to the LRA. In Appendix C, Section 4.1.3, "Air/Gas," of the LRA, the applicant describes the air/gas environments found at St. Lucie Units 1 and 2. Aging effects of components exposed to the air/gas environment depend, in part, on the type of air/gas environment, the operating temperature, and the water content. By letter dated July 1, 2002, the staff requested in RAI 3.3.1-1 that the applicant provide additional information on the characteristic parameters of the air/gas environments applicable to the CVCS components and on the basis by which the applicant determined that there are no aging effects requiring management for those components that are exposed to the air/gas environment.

In its response dated September 26, 2002, the applicant stated that Table 3.3-1 (pages 3.3-13 and 3.3-14) of the LRA indicates which CVCS components are exposed to internal air/gas environments. These CVCS components are the volume control tanks, the boric acid makeup tanks, and the associated valves, piping/fittings, and tubing/fittings which are located above the water level in these tanks. The type of air/gas environment and the bases for the determination that no aging effects exist that require management for these components are provided below.

- The volume control tanks, internal gas space surfaces and associated valves, piping/fittings, and tubing/fittings are exposed to a nonwetted hydrogen environment with traces of nitrogen, oxygen, and helium at a temperature less than 150 °F. The construction material of these components is stainless steel. Per Appendix C, Sections 5.1 and 5.2 (pages C-11 and C-14, respectively), to the LRA, this material is not susceptible to loss of material or SCC in this environment. A review of St. Lucie plant-specific operating experience validated that there are no aging effects requiring management for these components.

- The boric acid makeup tanks, internal gas space surfaces and associated valves, piping/fittings, and tubing/fittings are exposed to an air/gas environment of indoor not-air-conditioned air at a maximum temperature of 104 °F. The construction material of these components is stainless steel. Per Appendix C, Sections 5.1 and 5.2 (pages C-11 and C-14 respectively), to the LRA, this material is not susceptible to loss of material or

SCC in this environment. A review of St. Lucie plant-specific operating experience validated that there are no aging effects requiring management for these components.

Therefore, the applicant concluded that no aging effects requiring management have been identified for these components.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.1-1 clarifies and satisfactorily resolves this item because it provided the characteristic parameters of the air/gas environments applicable to these CVCS components, demonstrated that there are no aging effects requiring management for these components, and described the plant-specific operating experience which validates the conclusion.

Components of the CVCS that are exposed externally to the outdoor environment and the outdoor environment characteristic of the ECCS pipe tunnel are stainless steel piping/fitting (refueling water tanks to charging pump suctions) and bolting (mechanical closures, both carbon steel and stainless steel). The outdoor environment is characterized by moist, salt-laden air, a temperature range of 27 °F to 93 °F, 73 percent average humidity, and exposure to weather, including precipitation and wind. The applicant identified no applicable aging effects for CVCS components that are exposed externally to an outdoor environment with the exception of SCC and loss of material for stainless steel components located in the ECCS pipe tunnel. By letter dated July 1, 2002, the staff requested, in RAI 3.3.1-2, that the applicant explain the difference between the outdoor environments described in Appendix C, Section 4.2.1, to the LRA, and the outdoor environment in the ECCS pipe tunnel. Staff also asked FPL to explain how this difference leads to differences in aging effects.

In its response dated September 26, 2002, the applicant stated that as discussed in Appendix C, Section 5.2 (page C-14), to the LRA, sensitized stainless steels exposed to atmospheric conditions with high levels of contaminants (e.g., salt water) are considered potentially susceptible to SCC. Additionally, as discussed in LRA Appendix C, Section 5.1 (page C-11), pitting of stainless steel in an outdoor environment at St. Lucie depends on its location within the plant site. Experience at St. Lucie has identified pitting and SCC in the non-stress-relieved, heat-affected zone regions of weld joints of stainless steel piping located in the ECCS pipe tunnels that are exposed to the site's marine environment (LRA Table 3.2-2, page 3.2-19).

The applicant stated that the terms "tunnels" and "trenches" are synonymous at St. Lucie. Components located in the ECCS trenches at St. Lucie have greater susceptibility to pitting and cracking due to their potential for increasing external contamination. These trenches are located in proximity to the discharge canals on the ocean side of the plant. The turbulence of ocean water at the plant discharge promotes increased chloride concentrations in the air and chloride deposition on plant equipment located at low points in the proximity of the discharge canals. The ECCS trenches are low points and are covered throughout most of their length, therefore components located in the trenches tend to collect chlorides and do not have the benefit of periodic rainfalls that rinse the surfaces free of contaminants. Components located at above-ground elevation or in open trenches/pits (such as component cooling water stainless steel components) which are exposed to an outdoor environment (i.e., including rainfall) have not experienced SCC. Therefore, the applicant concluded that the potential for external pitting and cracking due to SCC at St. Lucie depends upon the localized environment of the components.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.1-2 clarifies and satisfactorily resolves this item because the applicant explained the differences between the outdoor environment and the outdoor environment characteristic of the ECCS pipe tunnel and also explained how this difference leads to differences in aging effects which are validated by the plant operating experience.

For carbon steel bolting exposed to outdoor, indoor not-air-conditioned, and containment air environments, no aging effects are identified in Table 3.3-1. By letter dated July 1, 2002, the staff requested, in RAI 3.3-1, that the applicant provide a basis for not considering aging effects on bolting from exposure to these environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER. The staff concluded that this RAI is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the CVCS SSCs to the environments described in Section 2.3.3.1 and Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant identified the applicable aging effects that are appropriate for the combination of materials and environments of concern.

3.3.1.2.2 Aging Management Program

In Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA, the applicant credited the following AMPs for managing the aging effects in the CVCS system.

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Tables 3.3-1, the staff concludes that the AMPs identified above will effectively manage the aging effects of the CVCS so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.3 Conclusions

The staff reviewed the information in Section 2.3.3.1, Table 3.3-1 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the CVCS will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the CVCS, as required by 10 CFR 54.21(d).

3.3.2 Component Cooling Water

3.3.2.1 Summary of Technical Information in the Application

The component cooling water system removes heat from safety-related and non-safety- related components during normal and emergency operation. The component cooling water pumps circulate component cooling water through heat exchangers and coolers that are associated with other systems. The component cooling water heat exchangers transfer the heat from these systems to the intake cooling water. The component cooling water system is described in Sections 9.2.2 of the UFSARs for Units 1 and 2.

3.3.2.1.1 Aging Effects

Components of the component cooling water system are described in Section 2.3.3.2 of the LRA as being within the scope of license renewal and subject to an AMR. Table 3.3-2, pages 3.3-18 through 3.3-22, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), bolting, heat exchangers, tanks, orifices, piping, tubing and fittings, and sightglasses. The component cooling water component materials of carbon steel, stainless steel, cast iron, aluminum brass, and aluminum bronze are exposed to internal air/gas environments of raw water (salt water) or treated water, and external environments of containment air, outdoor, indoor not-air-conditioned, and leaking borated water component cooling water. The corresponding aging effect requiring management is loss of material. The component cooling water aluminum brass heat exchanger tubes are exposed to raw water at the inside surface and treated water at the outside surface. The corresponding aging effect requiring management is fouling. The component cooling water bolting could be exposed to borated water leaking from an adjacent system or a component containing borated water. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the component cooling water system:

- *Chemistry Control Program*
- Intake Cooling Water Inspection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Pipe Wall Thinning Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the component cooling water system will be adequately managed by these AMPs for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 Staff Evaluation

The applicant described its AMR of the component cooling water system for license renewal in Section 2.3.3.2, Section 3.3, and Table 3.3-2 (pages 3.3-18 through 3.3-22). The process of identifying of the aging effects is summarized in Appendix C to the LRA, and descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the component cooling water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.2, Table 3.3-2 (pages 3.3-18 through 3.3-22), and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

In Appendix C, Section 5.1, the applicant stated that in an environment with extremely low oxygen content (less than 0.1 parts per million [ppm]), crevice corrosion is insignificant. Also the applicant stated that oxygen is required for pitting corrosion. The staff did not agree with this discussion of the role of oxygen in crevice and pitting corrosion because oxygen can be a contributor, but is not needed for crevice and pitting corrosion of metal. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-1, the applicant to provide references to support its position. In its response dated September 26, 2002, the applicant stated that the oxygen criterion associated with loss of material due to crevice corrosion is based on the industry guidance document developed by the Babcock and Wilcox Owners Group. This document references a *Corrosion and Wear Handbook for Water-Cooled Reactors* by D.J. DePaul, McGraw-Hill, New York. The applicant also stated that it did not credit low oxygen with precluding crevice or pitting corrosion in the component cooling water system. Instead, it credited the control of contaminants under the Chemistry Control Program and the use of corrosion inhibitors (molybdate and nitrite) to preclude loss of material due to corrosion. The applicant stated that the Chemistry Control Program was developed in accordance with the guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," as described in LRA Appendix B, Subsection 3.2.5.2 (page B-33).

Furthermore, in its December 27, 2002, response to RAI B.3.2.5-2 concerning the Chemistry Control Program, the applicant stated that a review of St. Lucie plant-specific operating experience was performed as part of the AMR review process for the component cooling water system to identify any age-related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective Chemistry Control Program. The applicant noted that many component cooling water components have been inspected in the past as part of corrective maintenance or the Periodic Surveillance and Preventive Maintenance Program (e.g., periodic pump overhauls). The applicant further stated, that during the past 12 months, more than 30 maintenance work orders were generated for the Units 1 and 2 component cooling water systems that required disassembly or removal of components. These work orders included repairs on instrumentation and other isolation valves, flow control valves, and check valve and relief valve internal inspections throughout the system. A majority of these components (e.g., the relief and isolation valves) entailed system locations where stagnant flow conditions exist. These locations are the likely candidates for pitting corrosion. The internal condition of the components has provided additional confidence that the Chemistry

Control Program is effective.

In addition, the applicant stated that the St. Lucie maintenance procedures typically specify inspection criteria or reference plant quality instructions that specify internal cleanliness requirements. As an example, the maintenance procedure for relief valve removal and testing includes a visual inspection of valve and piping mating surfaces for corrosion and pitting. The applicant also stated that the maintenance procedures specify a Class C cleanliness requirement for the component cooling water system. A Class C cleanliness requirement permits a tightly adhered oxide film or red oxide coating, as well as small areas of light rust, but pitting would not be acceptable. The applicant further stated that any significant degradation identified during these inspections would have been documented under the plant's Corrective Action Program. Therefore, the applicant concluded that the Chemistry Control Program is an effective AMP for managing the aging effects as discussed.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.2-1 clarifies and satisfactorily resolves the item because the applicant credits the Chemistry Control Program to preclude pitting and crevice corrosion and the plant operating experience verifies the effectiveness of this AMP in managing the aging effects due to pitting and crevice corrosion.

The applicant did not identify cracking due to SCC as an aging effect for the component cooling water system components exposed to treated water. However, stainless steel components exposed to treated water can experience cracking due to SCC. In addition, field experience reported in Appendix C to EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," indicates that if component cooling water is treated with nitrite as a corrosion inhibitor, carbon steel components exposed to treated water can experience IGSCC. Cracking of component cooling water piping is also reported in NRC Licensee Event Report LER 91-019-00, "Loss of Containment Integrity due to Crack in Cooling Water Piping," October 26, 1991. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-2, the applicant to provide the basis for excluding cracking as an applicable aging effect for component cooling water system carbon and stainless steel components exposed to treated water. In its response dated September 26, 2002, the applicant referred to LRA Appendix C, Section 5.2 (page C-14), which states that SCC of stainless steel components is not considered an aging effect requiring management in a treated water environment with a temperature of less than 140°F. The operating temperature of the component cooling water at St. Lucie Units 1 and 2 is less than 90 °F, which is significantly below the SCC threshold temperature of 140 °F. The applicant also stated that a review of St. Lucie plant-specific operating experience did not identify SCC in the stainless steel component cooling water system components as an aging effect requiring management. Therefore, SCC is not an aging effect requiring management for the component cooling water system stainless steel components. The staff agrees with the applicant's response that the stainless steel component cooling water system components are not susceptible to cracking due to SCC because they operate at a temperature below 140 °F.

The applicant further stated that industry data have not identified SCC as a significant problem for carbon steel components. The industry experience reported in EPRI TR-107396, "Closed Cycle Water Chemistry Guideline," concerning IGSCC of carbon steel involved nitrite-treated cooling water systems with a nitrite concentration of up to 6000 mg/L (approximately 6000 ppm). The nitrite concentration of the component cooling water system at St. Lucie is maintained at 300 to 450 ppm. A review of St. Lucie plant-specific operating experience did not identify SCC in carbon steel components as an aging effect requiring management. Therefore, IGSCC is not an aging effect requiring management for carbon steel components. The applicant also stated that FPL has reviewed Licensee Event Report (LER) 91-019-00 for the Surry Nuclear Station. Based on the applicant's review of this LER, the applicability to St. Lucie Units 1 and 2 could not be determined because a root cause was not identified in that LER.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.2-2 satisfactorily resolves this item because the applicant demonstrated that SCC is not an aging effect requiring management for the component cooling water system stainless steel and carbon steel components; this conclusion is validated by plant operating experience.

The component cooling water system heat exchanger components are internally exposed to the raw water environment on the tube side. These components include the aluminum brass heat exchanger tubes, aluminum bronze tubesheets, and carbon steel channels and doors. The aging effects for these components exposed to the raw water environment are identified in Table 3.3-2 and are discussed in Section 5.0 of Appendix C to the LRA. The raw water environment in the cooling canal is defined as salt water used as the ultimate heat sink. The applicant identified the applicable aging effects in this internal environment as loss of material (due to general, pitting, crevice, and galvanic corrosion, MIC, and selective leaching) and fouling. The applicant did not identify cracking due to SCC as an aging effect for the component cooling water system heat exchanger tubes exposed to raw water.

However, the operating experience at Turkey Point showed that the component cooling water system heat exchanger tubes, which are made of aluminum brass and exposed to raw water on the tube side, are susceptible to SCC. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-3, the applicant to provide the basis for excluding cracking as an applicable aging effect for the component cooling water heat exchanger tubes exposed to raw water. In its response dated November 27, 2002, the applicant stated that the metallurgical analysis of the failed Turkey Point component cooling water system heat exchanger tubes revealed that the cracking was initiated from the inside diameter (raw water side) and was located in the tube roll transition zone of the tube sheet. The cracking was determined to be transgranular stress-corrosion cracking (TGSCC) and was caused by the use of a new chemical injection system and the absence of sacrificial anodes. The tubes were replaced, the chemical injection system was removed from service, and zinc anodes were installed to prevent a recurrence.

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

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.2-3 satisfactorily resolves this issue because the applicant demonstrated that cracking due to SCC is not an aging effect requiring management for the component cooling water system heat exchanger tubes exposed to raw water.

The air/gas environment is an applicable internal environment for the carbon steel surge tanks, valves, piping and fittings, Unit 1 sight glasses, and Unit 2 sightglasses (stainless steel). The applicant did not identify any aging effects of these components in the air/gas environment. The aging effects associated with exposure to the air/gas environment are identified in Table 3.3-2 and discussed in Section 4.1.3, "Air/Gas," of Appendix C to the LRA. Several air/gas environment descriptions are provided for each of the air/gas environments found in the plant. Aging effects for component cooling water system components exposed to the air/gas environment depend, in part, on the type of air/gas environment, the operating temperature, and the water content. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-4, that the applicant provide the characteristic parameters of the air/gas environments applicable to the components found in the component cooling water system and the bases by which the determination of no aging effects requiring management was made for all the components exposed to the air/gas environment. In its response dated November 27, 2002, the applicant stated that the air/gas internal environment identified in LRA Table 3.3-2 (pages 3.3-18 and 3.3-19) applies to the component cooling water system surge tanks and associated valves, piping, and fittings located above the normal tank water level. This air/gas environment constitutes the atmospheric air of the surroundings (i.e., "indoor-not- air-conditioned" as defined in LRA Appendix C, Section 4.1.3, page C-8).

The applicant also stated that the AMR of the internal surfaces of the carbon steel component cooling water system surge tanks exposed to an air/gas environment identified general corrosion as a potential aging mechanism. Based on the location of these tanks and the limited air exchange provided by the 2-inch tank vents, aggressive chemical species will not be present and significant pitting is not expected. Additionally, these tanks are internally coated. The applicant stated that a calculation was performed to analyze whether the 80-mil design corrosion allowance for these tanks will accommodate any potential internal corrosion. Utilizing conservative corrosion rates from Tables 6-1 and F-1 of the Metals and Ceramics Information Center (MCIC) report, "Corrosion of Metals in Marine Environment" (July 1986) by J.A. Beavers, G.H. Koch, and W.E. Berry, the worst-case internal loss of material is calculated to be 76 mils (3 mils/yr x 8 yr + 1 mil/yr x 52 yr) over the life of the plant. These corrosion rates are based upon comprehensive evaluations of corrosion damage to steel exposed to the tropical atmosphere in the Panama Canal Zone. In addition, the applicant stated that the corrosion rate decreases with time due to the build up of an oxidation layer, which will tend to provide some protection of the bare metal underneath. The use of this corrosion rate assumes that no preventive measures (i.e., existing coatings) have been implemented since original installation and thus incorporates inherent design margin. Based on these results, the minimum required design wall thickness of the tanks is maintained. Therefore, loss of material due to corrosion of the internal surfaces of the upper portion of the component cooling water system surge tanks, which are exposed to an air/gas environment, is not an aging effect requiring management. The applicant also stated that plant operating experience supports this conclusion.

The applicant further stated that the AMR of the internal surfaces of the small diameter carbon steel vent valves and schedule 80 pipe/fittings associated with the level switches/sight glasses of the component cooling water system surge tanks exposed to an air/gas environment identified general corrosion as a potential aging mechanism. As discussed above, these tanks are located inside buildings and are vented by a 2-inch vent valve. There is limited air exchange through the vent valve. Therefore, aggressive chemical species will not be present and significant pitting is not expected. The rate of general corrosion is expected to be low. However, even assuming a conservative corrosion rate of 76 mils in 60 years (as discussed above), loss of pressure boundary integrity will not occur because adequate wall thickness will remain. The approximate wall thickness of 1-inch schedule 80 piping is 180 mils. The wall thickness of components, such as valves, is even greater. The minimum required wall thickness for these components is 2 mils. Therefore, the remaining wall thickness of 104 mils is more than adequate to meet design requirements, and adequate corrosion allowance exists for these components. Additionally, a review of St. Lucie plant-specific operating experience did not identify internal corrosion of these components as an aging effect requiring management. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the component cooling water system surge tanks (which are exposed to an air/gas environment) is not an aging effect requiring management. The staff has reviewed Tables 6-1 and F-1 of the MCIC report referenced by the applicant and determined that the corrosion rates used by the applicant are conservative. According to the data in these tables, the corrosion rate reduces from 2.8 mils for the 1st year to 1.1 mils for the 8th year (12.6 mils total for 8 years).

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.2-4 satisfactorily resolves this issue because the applicant used a conservative corrosion rate to conclude that loss of material due to corrosion is not an aging effect requiring management for these component cooling water system components; the plant-specific operating experience supports this conclusion.

The component cooling water system contains some carbon steel components (e.g., CCW surge tanks, pumps, heat exchanger shells, valves, piping/fittings) and bolting that are externally exposed to outdoor, indoor not-air-conditioned, and containment air environments. The applicant has identified loss of material as an aging effect for all carbon steel components, except bolting, exposed externally to these environments. For carbon steel bolting exposed to outdoor, indoor not-air-conditioned, and containment air environments, no aging effects are identified in Table 3.3-1. By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to these environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER, and the issue is characterized as resolved.

A few components in the component cooling water system have external surfaces that may be exposed to borated water leaks. By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response, documented in Section 3.3.17.2 of the SER, concluded that the issue is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the RAIs, the staff finds that the aging effects that result from contact of the component cooling water system SSCs with the environments described in Section 2.3.3.2 and Table 3.3-2 (pages 3.3-18 through 3.3-22) of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified for the combination of materials and environments listed.

3.3.2.2.2 Aging Management Programs

In Table 3.3-2, pages 3.3-18 through 3.3-22, of the LRA, the applicant credited the following AMPs for managing the aging effects in the component cooling water system.

- Chemistry Control Program
- Intake Cooling Water Inspection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Pipe Wall Thinning Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program, Galvanic Corrosion Susceptibility Inspection Program, Pipe Wall Thinning Inspection Program, Systems and Structures Monitoring Program, and Boric Acid Wastage Surveillance Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

The Intake Cooling Water Inspection Program is credited with managing the aging effects of several components in auxiliary systems and is, therefore, considered a system-specific AMP. The staff's evaluation of the Intake Cooling Water Inspection Program is described in Section 3.3.0.2 of this SER.

Based on its review of LRA Table 3.3-2, the staff concludes that the AMPs identified above will effectively manage the aging effects of the component cooling water system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3 Conclusions

The staff reviewed the information in Section 2.3.3.2 and Table 3.3-2 of the LRA and the additional information included in the applicant's responses to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the component cooling water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the component cooling water system, as required by 10 CFR 54.21(d).

3.3.3 Demineralized Makeup Water (Unit 2 Only)

3.3.3.1 Summary of Technical Information in the Application

The demineralized makeup water provides makeup water to various systems throughout the plant. The intended function of the components in the demineralized makeup water system is to maintain pressure boundary integrity. Details of the demineralized makeup water system are described in the Unit 2 UFSAR, Section 9.2.3.

3.3.3.1.1 Aging Effects

Components of the demineralized makeup water system are described in Section 2.3.3.3 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-3, page 3.3-23, of the LRA lists individual components of the system including stainless steel valves (pressure boundary only), piping, fittings, and carbon steel bolting (mechanical closures). Stainless steel components are identified as subject to loss of material from exposure to treated water. Exposure of stainless steel components to an indoor-non-air-conditioned environment has no aging effects. Exposure of carbon steel bolting to an indoor-non-air-conditioned environment has no aging effects.

3.3.3.1.2 Aging Management Programs

The Chemistry Control Program is utilized to manage aging effects in the demineralized makeup water system. This AMP is described in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the demineralized makeup water system will be adequately managed by this AMP for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.2 Staff Evaluation

The applicant described its AMR for the demineralized makeup water system for license renewal in Section 2.3.3.3, Section 3.3, and Table 3.3-3 (page 3.3-23) of the LRA. The process of identifying aging effects is summarized in Appendix C to the LRA, and a description of the AMP is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the demineralized makeup water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.3, Table 3.3-3 (page 3.3-23), and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER, and the issue is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the demineralized makeup water system SSCs with the environments described in Section 2.3.3.3 and Table 3.3-3 (page 3.3-23) of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.3.2.2 Aging Management Programs

In Table 3.3-3 on page 3.3-23 of the LRA, the applicant credited the Chemistry Control Program for managing the aging effects in the demineralized makeup water system.

This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-3, the staff concludes that the AMP identified above will effectively manage the aging effects of the demineralized makeup water system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.3 Conclusions

The staff reviewed the information in Section 2.3.3.3 and Table 3.3-3 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the demineralized makeup water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the demineralized makeup water system, as required by 10 CFR 54.21(d).

3.3.4 Diesel Generators and Support Systems

3.3.4.1 Summary of Technical Information in the Application

The diesel generators and support systems provide alternating current (AC) power to the onsite electric distribution system to ensure the capability for a safe and orderly shutdown. The diesel generators and support systems consist of the diesel generators, air intake and exhaust system, air start system, fuel oil system, lube oil system, and cooling water system. Details of the diesel generators are provided in the Unit 1 UFSAR, Section 8.3, and the Unit 2 UFSAR, Section 8.3. Details of the diesel generator support systems are provided in Sections 9.5 of the UFSARs for Units 1 and 2.

3.3.4.1.1 Aging Effects

Components of the diesel generators and support systems are described in Section 2.3.3.4 of the LRA as being within the scope of license renewal and subject to an AMR. In Table 3.3-4, (pages 3.3-24 through 3.3-40) of the LRA, the applicant lists individual components of the system including diesel oil storage tanks, day tanks, pumps, valves, air start motors (pressure boundary only), heat exchangers, silencers, flame arrestors, filters, strains, flexible hoses, expansion joints, orifices, thermowells, sight glasses, piping, tubing, and fittings.

The components in the air intake and exhaust system are fabricated from carbon steel, polyester/rubber, rubber, and stainless steel. These components are exposed to an internal environment of air/gas and an indoor not-air-conditioned external environment consisting of outside air with uncontrolled temperature and humidity. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to an air/gas internal environment. Cracking is identified for the polyester/rubber and rubber components exposed to an air/gas internal environment. No aging effect is identified for the stainless steel components exposed to air/gas internal environment. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to an indoor not-air-conditioned external environment. Cracking is identified for the polyester/rubber and rubber components exposed to an indoor not-air-conditioned external environment. No aging effect is identified for the stainless steel components exposed to an indoor not-air-conditioned external environment.

The components in the air start system are fabricated from carbon steel, stainless steel, aluminum alloy, and copper alloy. The air start system components are exposed to an internal environment of air/gas and an of indoor not-air-conditioned external environment. No applicable aging effect is identified for the carbon steel, stainless steel, aluminum alloy, and copper alloy components exposed to the internal air/gas environment. Loss of material is identified as an aging effect for the carbon steel components exposed to an external indoor not-air-conditioned external environment.

The components in the fuel oil system are fabricated from carbon steel, stainless steel, bronze, copper, and aluminum. These components are exposed to an internal environment of fuel oil and air/gas. Loss of material is identified as an aging effect for the carbon steel, stainless steel, and copper components exposed to an internal environment of fuel oil. Loss of material is identified as an aging effect for the carbon steel fuel oil tanks exposed to an air/gas environment due to the potential for moisture contamination. Loss of material is identified as an aging effect for the Unit 1 carbon steel fuel oil tanks exposed to an external outdoor environment outdoor and for the Unit 2 carbon steel fuel oil tanks exposed to indoor not-air-conditioned external environment.

The components in the lube oil system are fabricated from carbon steel, cast iron, stainless steel, brass, bronze, aluminum, and glass exposed to an internal environment of lube oil, treated water, and air/gas. Loss of material and fouling are identified as aging effects for the carbon steel, stainless steel, and brass components exposed to a treated water (other) internal environment. Fouling has been identified as an aging effect requiring management for brass components exposed to an internal environment of treated water. No aging effect is identified for those components exposed to lube oil or air/gas internal environment. Loss of material is identified as an applicable aging effect for the carbon steel and cast iron components exposed to an indoor not-air-conditioned external environment.

The components in the cooling water system are fabricated from carbon steel, brass, copper, stainless steel, rubber, and Plexiglas exposed to treated water. Loss of material and fouling are identified as aging effects for the carbon steel, brass, copper, and stainless steel components exposed to a treated water internal environment. Cracking is identified as an aging effect for rubber and Plexiglas components exposed to a treated water internal environment. Cracking is identified as an aging effect for Plexiglas components exposed to an internal air/gas environment. Loss of material is identified as an aging effect for the carbon steel, copper, and aluminum cooling water system components exposed to an indoor not-air-conditioned external environment. Cracking is identified as an aging effect for the rubber and Plexiglas components exposed to an indoor not-air-conditioned external environment. Fouling is identified as an aging effect for the cooling water radiator fins exposed to an indoor not-air-conditioned external environment.

3.3.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the diesel generators and support systems.

- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Fuel Oil Chemistry Subprogram
- Chemistry Control Program
- Closed Cycled Cooling Water System Chemistry Subprogram
- Periodic Surveillance and Preventive Maintenance Program

Description of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generators and support systems will be adequately managed by these AMPs for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.2 Staff Evaluation

The applicant described its AMR for the diesel generators and support systems for license renewal in Section 2.3.3.4, Section 3.3, and Table 3.3-4 (pages 3.3-24 through 3.3-40) of the LRA. The process of identifying the aging effects is summarized in Appendix C to the LRA. Descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generators and support systems will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.4, Table 3.3-4 (pages 3.3-24 through 3.3-40), and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

In Section 9.5.6.3, "System Evaluation," on page 9.5-12b of the Unit 2 UFSAR, the applicant stated that the air receiver for the air start system of the EDG collects moisture to preclude fouling of the air start valve with moisture and contamination.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-1, the applicant to 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. In its response dated September 26, 2002, the applicant stated that in Table 3.3-4 (page 3.3-28) of the LRA, the air start and intake system internal environment for the Unit 2 startup air tanks, and associated valves, piping, and fittings, was incorrectly identified as dry air/gas. Since the Unit 2 air start system does not have air dryers, the startup 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 Section 9.5.6.3 of the Unit 2 UFSAR, the air receiver for the air start system of the EDG 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 to indicate a wetted air/gas environment and to 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.

The applicant further stated that based upon moisture removal by periodic blowdown of the startup 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. The components downstream of the startup air tanks are made of 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 (page 3.3-28) of the LRA was revised to incorporate the information that the aging effect of stainless steel startup air tanks, drain piping, and valves (Unit 2 only) in an air/gas (wetted) environment is loss of material and the AMP is the Periodic Surveillance and Preventive Maintenance Program.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant corrected Table 3.3-4 of the LRA to indicate a "wetted air/gas" environment and credited the Periodic Surveillance and Preventive Maintenance Program with managing the effects of aging for the components identified in RAI 3.3.4-1.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-2, the applicant to provide justification for not identifying loss of material as an aging effect for air start system components fabricated from aluminum alloy or copper alloy exposed externally to an indoor not-air-conditioned environment. In its response dated September 26, 2002, the applicant stated that, as discussed in LRA Appendix C, Section 5.1 (page C-11), and based upon industry guidance developed by the B&W Owners Group, both aluminum and copper alloys have high resistance to corrosion in atmospheric environments. As a result, no external aging effects requiring management were identified for these components. This conclusion is supported by a review of St. Lucie plant-specific operating experience which identifies no instances of loss of material for the air start system components fabricated from aluminum or copper alloys exposed to an indoor not-air-conditioned external environment.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant has demonstrated that both aluminum and copper alloys have high resistance to corrosion in atmospheric environments and are not subject to loss of material. These findings are validated by the plant is operating experience.

In Table 3.3-4 on page 3.3-33 of the LRA, the applicant identifies loss of material as a potential aging effect of the carbon steel fuel oil tanks exposed to an air/gas environment, as a result of the potential for moisture contamination. By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-3, the applicant to provide justification for not identifying loss of material for the carbon steel day tanks, which are also exposed to the same air/gas environment. In its response dated September 26, 2002, the applicant stated that the Unit 1 DOSTs are large vented tanks exposed to an outdoor environment. The Unit 2 DOSTs are inside a missile shield enclosure and are exposed to an indoor not-air-conditioned external environment. These tanks are susceptible to condensation on the inside surfaces of the air/gas space. Because of the large surface areas exposed to ambient temperature changes. The condensation collects in the tank bottoms and must be periodically drained off. The day tanks, however, are small tanks and are located inside the EDG buildings. They do not experience large ambient temperature changes and are not subject to significant condensation. Additionally, due to periodic testing of the diesel generators, the fuel in these tanks is consumed and replenished frequently, and therefore, collection of moisture is not anticipated. Also, the actual day tank internal environment is fuel oil vapor that protects the internal surfaces from corrosion. Therefore, loss of material is not an aging effect requiring management for the diesel generator fuel oil system internal air/gas environments, with the exception of the DOSTs.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue because the applicant has demonstrated that these day tanks are located inside the buildings and are not subject to significant condensation. In addition, collection of moisture is not anticipated in the day tanks.

In Table 3.3-4 on page 3.3-26 of the LRA, the applicant states that plant experience shows a history of loss of material as a result of corrosion of the copper and aluminum cooling water radiator fins in the cooling water system exposed to an indoor not-air-conditioned environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-4, the applicant to explain why other copper and aluminum alloy components exposed to indoor or outdoor environments in the diesel generators and support systems are not subject to aging effects requiring aging management. These components include tubing/fittings, air start motors, air start motor lubricators, frame arrestors (in an outdoor environment), and filter housings. In its response dated September 26, 2002, the applicant stated that there has been no St. Lucie plant-specific experience that identifies loss of material as an aging effect for other cooling water system components fabricated from aluminum alloy or copper alloy exposed to an indoor not-air-conditioned external environment. According to LRA Appendix C, Section 5.1 (page C-11), and widely available engineering sources, both aluminum and copper alloys are highly corrosion resistant in nonaggressive environments and have good corrosion resistance in atmospheric environments.

However, St. Lucie plant-specific operating experience has identified loss of material of the radiator fins that ultimately resulted in replacement of the radiator cores. This can be attributed to the corrosion rate of the fins. Per the MCIC report "Corrosion of Metals in Marine Environments," the corrosion rate for copper is 0.16 mil/yr and the corrosion rate for aluminum is 0.30 mil/yr. In most circumstances, this is an acceptable corrosion rate. However, due to the small thickness of the fins, the corrosion rate is more significant. Additionally, the radiator fins tend to filter and concentrate contaminants during diesel operation providing a more aggressive environment for corrosion. Therefore, loss of material is an aging effect requiring management for the radiator fins, as identified in LRA Table 3.3-4, page 3.3-26.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant demonstrated that the other copper and aluminum alloy components in the diesel generators and support systems exposed to indoor or outdoor environments are highly corrosion resistant in nonaggressive environments and are not subject to aging effects requiring aging management. In addition, the conclusions are validated by the plant operating experience.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER, and the issue is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the diesel generators and support systems SSCs with the environments described in Section 2.3.3.4 and Table 3.3-4 (pages 3.3-24 through 3.3-40) are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.4.2.2 Aging Management Programs

In Table 3.3-4 (pages 3.3-24 through 3.3-40) of the LRA, the applicant credited the following AMPs for managing the aging effects in the diesel generators and support systems.

- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Fuel Oil Chemistry Subprogram
- Chemistry Control Program
- Closed-Cycle Cooling Water System Chemistry Subprogram
- Periodic Surveillance and Preventive Maintenance Program

The Galvanic Corrosion Susceptibility Inspection Program, the Systems and Structures Monitoring Program, the Closed-Cycle Cooling Water System Chemistry Subprogram, and the Periodic Surveillance and Preventive Maintenance Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff's review of these common AMPs is documented in Section 3.0.5 of the SER. The Fuel Oil Chemistry Subprogram is credited with managing the aging effects of several components in auxiliary systems and is, therefore, considered a system- specific AMP. The staff's evaluation of the Fuel Oil Chemistry Subprogram is described in Section 3.3.0.1 of this SER.

Based on its review of LRA Table 3.3-4, the staff concludes that the AMPs identified above will effectively manage the aging effects of the diesel generators and support systems so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.3 Conclusions

The staff reviewed the information in Section 2.3.3.4 and Table 3.3-4 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generators and support systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the diesel generators and support systems, as required by 10 CFR 54.21(d).

3.3.5 Emergency Cooling Canal System

3.3.5.1 Summary of Technical Information in the Application

The emergency cooling canal system admits water from Big Mud Creek to provide the ultimate heat sink for St. Lucie Units 1 and 2. The emergency cooling canal and ultimate heat sink dam, which is located between the intake canal and Big Mud Creek, are included in the civil/structural screening described in Subsections 2.4.2.9 and 2.4.2.14, respectively, of the LRA. Details of the emergency cooling canal system are described in Section 9.2.7 of the UFSAR for Unit 1 and Section 9.2.5 of the UFSAR for Unit 2.

3.3.5.1.1 Aging Effects

In Section 2.3.3.5 of the LRA, the applicant describes the components of the emergency cooling canal system as being within the scope of license renewal and subject to an AMR. In Table 3.3-5 on page 3.3-41 of the LRA, the applicant lists individual components of the system including aluminum bronze valves, carbon steel piping and fittings, and carbon steel bolting. The aluminum bronze and carbon steel components that are exposed to raw water—salt water are subject to loss of material. Exposure of carbon steel components to embedded/encased environments has no aging effects.

3.3.5.1.2 Aging Management Programs

the Periodic Surveillance and Preventive Maintenance Program is utilized to manage aging effects in the emergency cooling canal system. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the emergency cooling canal system will be adequately managed by this AMP for the period of extended operation.

3.3.5.2 Staff Evaluation

The applicant described its AMR of the emergency cooling canal system for license renewal in Section 2.3.3.5, Section 3.3, and Table 3.3-5 (page 3.3-41) of the LRA. The process of identifying of the aging effects is summarized in Appendix C to the LRA. A description of the AMP is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the emergency cooling canal system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.5, Table 3.3-5 (page 3.3-41), and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed. By letter dated July 1, 2002, the staff issued RAI 3.3-3, pertaining to the chloride-related corrosion in the embedded/encased carbon steel piping/fitting. The staff's evaluation of the applicant's response, documented in Section 3.3.17.3 of this SER, concluded that the issue is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the emergency cooling canal system SSCs with the environments described in Section 2.3.3.5 and Table 3.3-5 (page 3.3-4) are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.5.2.2 Aging Management Programs

In Table 3.3-5, page 3.3-41 of the LRA, the applicant credited the Periodic Surveillance and Preventive Maintenance Program with managing the aging effects in the emergency cooling canal system. This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5.9 of this SER.

Based on its review of LRA Table 3.3-5 and the applicant's response to RAI 3.3-3, the staff concludes that the AMP identified above will effectively manage the aging effects of the emergency cooling canal system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5.3 Conclusions

The staff reviewed the information in Section 2.3.3.5 and Table 3.3-5 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the emergency cooling canal system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the emergency cooling canal system, as required by 10 CFR 54.21(d).

3.3.6 Fire Protection

3.3.6.1 Summary of Technical Information in the Application

The fire protection systems protect plant equipment to ensure safe plant shutdown in the event of a fire. This section addresses the fire protection systems that are part of the auxiliary systems. The fire-rated assemblies are included in the civil/structural AMR of the LRA. They are discussed and evaluated in Section 3.5 of this SER.

The fire protection systems consist of a fire water supply system that supplies city water to the standpipe and hose station systems, the automatic fire suppression systems, and the plant fire hydrants located in various areas of the plant for firefighting purposes. The fire water supply system consists of two storage tanks, two motor-driven fire water pumps, isolation and control valves, and the 12-inch cement-lined cast iron underground pipe that loops around the plant. The fire protection systems consist of four types of fire suppression systems. The pre-action sprinkler systems are located indoors to protect safety-related systems. The wet pipe systems are located in the turbine building. The fixed water spray systems are located in the yard to protect various oil storage tanks and transformers. The halon system is located in the RAB to protect the cable spread room equipment (Unit 1 only). The RCP oil collector system collects leaking RCP lube oil to a collection tank. Details of the fire protection systems are described in Unit 1 UFSAR, Section 9.5A, and Section 3.1.3 and Unit 2 UFSAR Section 9.5A and Section 3.1.3.

3.3.6.1.1 Aging Effects

Components of the fire protection systems are described in Section 2.3.3.6 of the LRA as being within the scope of license renewal and subject to an AMR. Table 3.3-6, pages 3.3-42 through 3.3-47, of the LRA lists individual components of the system including city water storage tanks, fire water pumps, valves, piping, hydrants, tubing/fittings, sprinkler heads, vortex breakers, and filters. Loss of material is identified as an applicable aging effect for the carbon steel, cast iron, copper alloy, and stainless steel exposed to an internal environment of raw water—city water. Loss of material is also identified as an applicable aging effect for the carbon steel city water storage tanks because of the humid air in the lower portion of the tanks. Loss of material has been identified as an aging effect for the cast iron components exposed to an air/gas—atmospheric air environment. No aging effect is identified for the carbon steel, galvanized carbon steel, copper alloy, stainless steel, aluminum, and glass components exposed to the air/gas environment. No aging effect is identified for the carbon steel, stainless steel, aluminum, and glass components exposed to the lube oil environment.

Loss of material is identified as an applicable aging effect for the carbon steel and cast iron components exposed to an external outdoor environment. No aging effect is identified for the copper alloy and stainless steel components exposed to the outdoor environment. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to the external environment of containment air. No aging effect is identified for the stainless steel, aluminum, and glass components exposed to the containment air environment. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to an external environment of borated water leaks. Loss of material is identified as an applicable aging effect for the cast iron components exposed to an external buried condition environment. No aging effect is identified for the cast iron components exposed to an embedded/encased external environment. The applicable aging effects in the indoor not-air-conditioned environment include loss of material for the carbon steel and cast iron components. No aging effect is identified for the stainless steel, copper alloy, and galvanized carbon steel components exposed to an indoor not-air-conditioned external environment.

3.3.6.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects of the fire protection systems.

- Fire Protection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Description of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the fire protection systems will be adequately managed by these AMPs for the period of extended operation.

3.3.6.2 Staff Evaluation

In Section 2.3.3.6, Section 3.3, and Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, the applicant described its AMR of the fire protection system. The process of identifying the aging effects is summarized in Appendix C to the LRA. A description of the AMPs is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fire protection systems will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.6, Table 3.3-6 (pages 3.3-42 through 3.3-47), and the applicable sections in Appendix C to the LRA. During the review, the staff determined that additional information was needed.

In Section 3.2.8, "Fire Protection Program," on page B-39 of Appendix B to the LRA, the applicant states that the Fire Protection Program is credited with managing the aging effects of loss of material attributable to corrosion including selective leaching.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-1, the applicant to identify those components and locations that are susceptible to leaching. In its response dated September 26, 2002, the applicant stated that as described in LRA Appendix C, Section 5.1 (page C-13), loss of material due to selective leaching (dealloying) has been identified as a potential aging effect for gray cast iron and certain brass or bronze materials. Specifically, brass and bronze with greater than 15 percent zinc, or aluminum bronze with greater than 8 percent aluminum, are susceptible to dealloying. The fire protection systems' copper alloy components have a zinc content of less than 15 percent; therefore, these components are not susceptible to loss of material due to selective leaching. There are no aluminum bronze components in the fire protection systems. For gray cast iron exposed to an internal environment of raw water—city and an external buried environment loss of material due to selective leaching is an aging effect requiring management as shown in LRA Table 3.3-6, pages 3.3-42 and 3.3-45.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant identified the components susceptible to loss of material due to selective leaching.

The fire water supply system consists of a 12-inch, cement-lined, cast-iron underground pipe that loops around the plant. The cement lining may degrade due to cracking or spalling that may cause flow blockage in the piping. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-2, the applicant to explain why an AMR was not performed for the cement lining. In its response dated September 26, 2002, the applicant stated that the cement lining in the fire protection water supply (suppression water distribution) system does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). The cement lining performs the preventive function of minimizing the potential for corrosion. However, the cement lining is not credited with eliminating aging effects. The cement, or mortar, lining is consistent with American Water Works Association (AWWA)/C104/A21.4. The thickness is nominally 1/16-inch. A review of St. Lucie plant-specific operating experience did not identify any instances of flow blockage of the fire protection suppression water distribution system due to piping lining failures. The applicant also stated that fire protection components are periodically flushed, performance tested, and inspected. Significant internal lining failures would be detected by changes in flow or pressure or by evidence of cement products during flushing of the system. Therefore, the applicant concluded that an AMR is not required for the cement lining of the fire protection suppression water distribution system.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant clarified that the cement lining in the fire protection water supply (suppression water distribution) system does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). The applicant also demonstrated that lining failures would be detected while flushing the system. Therefore, an AMR is not required for the cement lining of the fire protection suppression water distribution system.

The fire water supply system consists of a 12-inch, cement-lined, cast-iron underground pipe that loops around the plant. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-3, the applicant to explain how the aging effect of loss of material as a result of corrosion is managed for the external surfaces of the buried pipe. In its response dated September 26, 2002, the applicant stated that the St. Lucie fire water supply (suppression water distribution) cast-iron piping is buried in Class 1 fill and is located above ground water elevation. Additionally, this piping is coated with a coal tar epoxy to minimize the potential for corrosion. The applicant also stated that it has considered external loss of material to be an aging effect requiring management for the fire water supply cast-iron piping.

As indicated in Table 3.3-6 (page 3.3-45) of the LRA, the Fire Protection Program (LRA Appendix B, Section 3.2.8, page B-39) is credited with managing the external aging effect of loss of material for cast iron fire water supply piping. The fire water system is continuously pressurized and monitored. Any localized degradation of the external coating resulting in a corrosion cell would ultimately manifest itself in a leak in the piping. The resultant leakage would be detected by pressure monitoring instrumentation, and if the leak were large enough, a fire pump would automatically start indicating an unexpected system demand. Additionally, periodic performance testing under the Fire Protection Program is utilized to manage the external aging effects.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant demonstrated that the aging effect of loss of material in underground pipe will be adequately managed by the Fire Protection Program.

In Appendix B, Section 3.2.8, to the LRA, the applicant stated that functional testing and flushing of the fire protection systems clears away internal scale and corrosion products that could lead to blockage or obstruction of the system. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-4, the applicant to discuss why Table 3.3.6 of the LRA does not include biofouling as an applicable aging effect. In its response dated September 26, 2002, the applicant stated that the fire protection systems are filled with water classified as raw water—city water. The city water has been rough-filtered to remove large particles and has been purified but conservatively classified as raw water for the purposes of the AMR. The applicant further stated that macro-organisms would not be found in this water, and therefore, biofouling is not an applicable aging effect for the fire protection systems.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant explained that macro-organisms would not be found in the city water and therefore, biofouling is not an applicable aging effect for the fire protection systems.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects that result from contact of the fire protection systems' SSCs with the environments, as described in Section 2.3.3.6 and Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.6.2.2 Aging Management Programs

In Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, the applicant credited the following AMPs with managing the aging effects in the fire protection systems.

- Fire Protection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-6, the staff concludes that the AMPs identified above will effectively manage the aging effects of the fire protection systems so that there is reasonable assurance that the intended functions of the systems will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.3 Conclusions

The staff reviewed the information in Section 2.3.3.6 and Table 3.3-6 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the fire protection systems, as required by 10 CFR 54.21(d).

3.3.7 Fuel Pool Cooling System

3.3.7.1 Summary of Technical Information in the Application

The fuel pool cooling system removes decay heat from the fuel pool by circulating water through the fuel pool heat exchangers during normal plant operation. The heat from the fuel pool is transferred to CCW. The applicant described the safety-related means of fuel pool cooling for Unit 1 as pool boiloff and system makeup from intake cooling water without forced circulation through the heat exchanger. For Unit 2, the applicant stated that the safety-related means of fuel pool cooling is recirculating through the fuel pool heat exchangers. As a backup, Unit 2 fuel pool cooling can be accomplished by pool boiloff and system makeup from intake cooling water. Details of the fuel pool cooling system are described in Unit 1 UFSAR, Section 9.1.3, and Unit 2 UFSAR, Section 9.1.3.

3.3.7.1.1 Aging Effects

Components of the fuel pool cooling system are described in Section 2.3.3.7 of the LAR as being within the scope of license renewal and subject to an AMR. Table 3.3-7, pages 3.3-48 through 3.3-50, of the LRA lists individual components of the system including stainless steel pumps, valves (pressure boundary only), heat exchangers, thermowells, piping, tubing, fittings, and carbon steel spent fuel pool heat exchanger shell and tube support (Unit 2 only). Stainless steel components exposed to treated water and/or borated water are subject to the loss of material and fouling (inside diameter) aging effects. Carbon steel components exposed to treated water (as described in Section 4.1.1 of Appendix C to the LRA) are subject to the loss of material aging effect.

3.3.7.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the fuel pool cooling system.

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the fuel pool cooling system will be adequately managed by these AMPs for the period of extended operation.

3.3.7.2 Staff Evaluation

The applicant described its AMR for the fuel pool cooling system for license renewal in Section 2.3.3.7, Section 3.3, and Table 3.3-7 of the LRA. The process of identifying the aging effects is summarized in Appendix C to the LRA, and descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fuel pool cooling system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.7.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.7, Table 3.3-7 (pages 3.3-48 through 3.3-50), and the applicable sections in Appendix C to the LRA. The aging effects on the components exposed to the fuel pool cooling system environments, as described in Section 2.3.3.7 and Table 3.3-7, are consistent with the industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects have been identified, and that the aging effects listed are appropriate for these combinations of materials and environments.

3.3.7.2.2 Aging Management Programs

In Table 3.3-7 of the LRA, the applicant credited the following AMPs with managing the aging effects in the fuel pool cooling system.

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are also credited with managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-7, the staff concludes that the AMPs identified above will effectively manage the aging effects of the fuel pool cooling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.7.3 Conclusions

The staff reviewed the information in Section 2.3.3.7 and Table 3.3-7 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fuel pool cooling system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the fuel pool cooling system, as required by 10 CFR 54.21(d).

3.3.8 Instrument Air

3.3.8.1 Summary of Technical Information in the Application

The instrument air system provides a reliable source of dry, oil-free air for pneumatic instruments and controls and pneumatically operated valves. Instrument air contains electric driven air compressors. The instrument air system utilizes several compressors, each having a separate inlet filter, aftercooler, and moisture separator. The turbine cooling water system cools the compressors. The instrument air compressors discharge to a header connected to an air receiver, air dryer, and filter assembly. The compressed air header is divided into branch lines supplying to different areas of the plant, e.g., CCW area, RAB, fuel handling areas, and the SG blowdown treatment facility. Details of the instrument air system are described in Unit 1 UFSAR Section 9.3.1 and Unit 2 UFSAR Section 9.3.1.

3.3.8.1.1 Aging Effects

Components of the instrument air system are described in Section 2.3.3.8 of the LRA as being within the scope of license renewal and subject to an AMR. Table 3.3-8, pages 3.3-51 through 3.3-58, of the LRA lists individual components of the system, including valves (pressure boundary only), flasks/tanks, filters, strainers, heat exchangers, orifices, piping, tubing, hoses, fittings, air receivers, air dryers, shells, and bolting. The carbon steel instrument air receivers, dryers, compressor cooler shells and tube sheets, valve bodies, silencers, accumulators, piping and fittings, and galvanized carbon steel piping and fittings are internally exposed to a treated water or moist air/gas environment and externally exposed to indoor not-air-conditioned, outdoor, containment air, or leaking borated coolant environments. The corresponding aging effect requiring management is loss of material. The copper tubes and copper alloy tube sheets of compressor coolers, brass and bronze valve bodies, copper alloy sight glasses, stainless steel valve bodies, filters, and filter and strainer housings are internally exposed to a moist air/gas environment. The corresponding aging effect requiring management is loss of material. The instrument air compressor cooler copper tubes are internally exposed to a treated water or moist air/gas environment. The corresponding aging effect requiring management is fouling. The plastic valve bodies and rubber hoses are internally exposed to moist air/gas environment and externally exposed to an indoor not air-conditioned environment. The corresponding aging effect requiring management is cracking. The closure bolting could be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.8.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the instrument air system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

Descriptions of these AMPs are provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the instrument air system will be adequately managed by these AMPs for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.2 Staff Evaluation

The applicant describes its AMR of the instrument air system for license renewal in Section 2.3.3.8, Section 3.3, and Table 3.3-8 of the LRA. The process of identifying of the aging effects is summarized in Appendix C to the LRA, and descriptions of the AMPs are provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the instrument air system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.8, Table 3.3-8, and the applicable sections in Appendix C to the LRA. During its review, the staff determined that additional information was needed.

The instrument air system components located downstream of the air dryer are internally exposed to dry air/gas environment. These components include valve bodies, piping and fittings, accumulators, tubing, thermowells, flexible hoses, rupture discs, filter and filter housings, strainers, and orifices. These components are fabricated from copper-alloy, brass, bronze, aluminum, carbon steel, galvanized carbon steel, and stainless steel. The applicant stated that the dry air/gas environment does not introduce any applicable aging effect on these components.

However, this may not be supported by the industry operating experience. As an example, NRC IN 1987-28, "Air System Problems at U.S. Light Water Reactors," indicated that a loss of decay heat removal and significant primary system heatup at Palisades in 1978 and 1981 were caused by water in the air system. This experience implied that the air/gas system downstream of the dryer may not be dry. By letter dated July 1, 2002, the staff requested, in RAI 3.3.8-1, the applicant to provide the technical basis for not identifying loss of material as an applicable aging effect for the components downstream of the air dryer. In its response dated September 26, 2002, the applicant stated that NRC IN 1987-28 and GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment" were reviewed during its AMR of instrument air. St. Lucie, like many other U.S. nuclear power plants, experienced general corrosion of its instrument air component internal surfaces early in its operating life. A review of St. Lucie plant-specific operating experience identified leak test failures and internal piping corrosion that occurred in the 1980s. The investigation of these problems demonstrated that the onset of general corrosion downstream of the air dryers was attributed to the ineffectiveness of the original air dryers, in combination with the carbon steel construction of the system piping. To address these equipment problems, the instrument air dryers were replaced in 1989 with more effective desiccant dryers (including prefilter and after filters) and two new instrument air compressors were added with capacities and purification capabilities recommended by ANSI/Instrument Society of America (ISA)-S7.3, Quality Standard for Instrument Air. Additionally, FPL aggressively pursued improved system performance via upgraded maintenance procedures, additional training of operators, and verification of the system design. Since its completion of corrective actions associated with GL 88-14, St. Lucie instrument air has met the required air quality requirements and has not experienced corrosion-related problems downstream of the instrument air dryers.

The applicant further stated that St. Lucie addressed air quality issues downstream of dryers in FPL's response to GL 88-14. This response included the following one-time verifications, (1) verification that actual instrument air quality is consistent with manufacturers recommendations for safety-related components, (2) verification that maintenance practices, emergency procedures, and training are adequate, and (3) verification that the design of the entire system, including air or other pneumatic accumulators, is in accordance with its intended function, which incorporated testing of air operated valves.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.8-1 clarifies and satisfactorily resolves this item because the applicant has demonstrated that the instrument air dryer design change, maintenance procedure, and system design verification will ensure that loss of material is not an applicable aging effect for the instrument air system components located downstream of the air dryer.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the instrument air system SSCs to the environments described in Section 2.3.3.8 and Table 3.3-8 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified and the aging effects listed are appropriate for the combination of materials and environments described.

3.3.8.2.2 Aging Management Programs

In Table 3.3-8 of the LRA, the applicant credited the following AMPs for managing the aging effects in the instrument air system.

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-8, the staff concludes that the AMPs identified above will effectively manage the aging effects of the instrument air system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.3 Conclusions

The staff reviewed the information in Section 2.3.3.8 and Table 3.3-8 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the instrument air system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also conclude that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the instrument air system, as required by 10 CFR 54.21(d).

3.3.9 Intake Cooling Water System

3.3.9.1 Summary of Technical Information in the Application

The intake cooling water (ICW) removes heat from component cooling water, turbine cooling water, and SG open blowdown system, and discharges it to the condenser discharge canal. Intake cooling water from the intake structure flows through basket strainers located at the inlets of the component cooling, turbine cooling, and SG open blowdown heat exchangers, passes through the tube side of the exchangers, and flows to the discharge canal. Additionally, ICW provides a safety-related makeup source for fuel pool cooling. Details of the ICW are described in Unit 1 UFSAR Section 9.2.1 and Unit 2 UFSAR Section 9.2.1.

3.3.9.1.1 Aging Effects

Components of the ICW system are described in Section 2.3.3.9 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-9, pages 3.3-59 through 3.3-64, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), strainers, orifices, piping, tubing, fittings, thermowells, expansion joints, and bolting. The carbon steel and stainless steel valves and piping/fittings in main process lines and basket strainers are exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The carbon steel piping/fitting in the main process lines are exposed also to internal environment of air/gas. The corresponding aging effect requiring management is loss of material. The Monel orifices are exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The buried carbon steel piping/fittings are externally exposed to soil. The aging effect requiring management is loss of material. The submerged carbon steel piping/fittings (discharge) are exposed to external environment of raw water. The corresponding aging effect requiring management is loss of material. The aluminum brass heat exchanger tubes are exposed to internal environment of raw water. The corresponding aging effects requiring management are fouling and loss of material. The carbon steel bolting is exposed to external environment of leaking borated coolant. The corresponding aging effect requiring management is loss of mechanical closure integrity. The stainless steel and Monel bolting is exposed to external environment of raw water—salt water. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.9.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the ICW system.

- Periodic Surveillance and Preventive Maintenance Program
- Intake Cooling Water Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the ICW system will be adequately managed by these AMPs for the period of extended operation.

3.3.9.2 Staff Evaluation

The applicant described its AMR of the ICW system for license renewal in Section 2.3.3.9 and Section 3.3 of the LRA. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ICW system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.9, Table 3.3-9, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

Several stainless steel components in the ICW system are externally exposed to indoor not-air-conditioned environment. These components include pump and valve bodies, piping/fittings, tubing/fittings, and mechanical closure bolting. The applicant has identified loss of material as an applicable aging effect only for the pump bodies and not for any other stainless steel component. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-1, the applicant to provide technical basis for not identifying loss of material as an applicable aging effect for stainless steel piping/fittings and tubing/fittings in the ICW system externally exposed to indoor not-air-conditioned environment. In its response dated September 26, 2002, the applicant stated that pitting corrosion has been identified as a potential aging mechanism for the external surfaces of the above-ground stainless steel piping/fittings, tubing/fittings, orifices, and valves in the ICW system. Based on LRA Appendix C, Section 5.1 (page C-11), moisture must be present for pitting corrosion to occur. Stainless steel ICW components located in an indoor not-air-conditioned environment (LRA Table 3.0-2, page 3.0-3) are not subject to moisture unless specifically identified in the LRA tables. Additionally, visual inspections of these components and St. Lucie plant-specific operating experience have not identified pitting corrosion as an aging mechanism that could lead to loss of material. Therefore, loss of material due to corrosion is not an aging effect requiring management for these stainless steel components exposed to indoor not-air-conditioned environment.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.9-1 clarifies and satisfactorily resolves this item because visual inspections and plant operating experience have not identified pitting corrosion causing loss of material at the external surface of these stainless steel ICW components.

Several bronze, aluminum bronze, and aluminum brass components in the ICW system are externally exposed to outdoor or indoor not-air-conditioned environments. These components include pump and valve bodies, and piping/fittings. No aging effects are identified for these components which are exposed to outdoor or indoor not air-conditioned environment. In Section 5.1 of Appendix C to the LRA, the applicant also stated that bronze and brass are considered susceptible to pitting when zinc content is greater than 15 percent, and aluminum bronze is considered susceptible to pitting when the aluminum content is greater than 8 percent. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-2, the applicant to explain why loss of material is not an applicable aging effect for the bronze, aluminum bronze, and aluminum brass components in the intake cooling water system. In its response dated September 26, 2002, the applicant stated that the intent of LRA Appendix C, Section 5.1 (page C-11) is to indicate that moisture must be present for pitting to occur. Loss of material due to pitting corrosion is an applicable aging effect only if the bronze, brass, or aluminum bronze component is buried, submerged in fluid, or subject to wetting other than normal environment. The applicant further indicated that these components in the ICW system are not subject to external wetting.

On the basis of its review, the staff finds the applicant's response to RAI 3.3.9-2 acceptable because the ICW components addressed here are not subject to wetting externally and, therefore, are not susceptible to pitting corrosion.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of this SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-3 pertaining to the chloride-related corrosion in the embedded/encased carbon steel piping/fitting. The staff's evaluation of the applicant's response is documented in Section 3.3.17.3 of this SER and is characterized as resolved.

By letter dated March 28, 2003, the applicant provided its response to Open Item 3.0.5.10-1 concerning leakage detection. The staff's evaluation of the leakage detection is documented in Section 3.0.5.10.2 of this SER and is characterized as resolved. In its response to Open Item 3.0.5.10-1, the applicant also revised LRA Table 3.3-9. In particular, the applicant identified the air/gas environment as an applicable internal environment for the carbon steel ICW emergency lines to the spent fuel pool. In note (2) of Table 3.3-9, the applicant stated that based upon available corrosion allowance and conservative corrosion rate, loss of material due to general corrosion is not an aging effect requiring management for the subject piping. By letter dated May 30, 2003, the applicant provided supplemental information to support the basis for the above note (2). The applicant's calculation showed that with a conservative corrosion rate, the remaining wall thickness of the piping is more than adequate to meet design requirements and adequate corrosion allowance exists for the subject piping. Therefore, the applicant concluded that loss of material due to general corrosion is not an aging effect requiring management for the subject piping.

The staff finds that the applicant's changes to LRA Table 3.3-9 for the ICW emergency lines to the spent fuel pool is acceptable because that the applicant has used a conservative corrosion rate to demonstrate that loss of material due to general corrosion is not an aging effect requiring management for the above ICW emergency lines. It should be noted that the applicant has performed a similar corrosion rate calculation for CCW components in its response to RAI 3.3.2-4. The staff's evaluation of the applicant's calculation is documented in Section 3.3.2.2.1 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the ICW system SSCs to the environments described in Section 2.3.3.9 and Table 3.3-9, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.9.2.2 Aging Management Programs

In Table 3.3-9, of the LRA, the applicant credited the following AMPs for managing the aging effects in the ICW system.

- Periodic Surveillance and Preventive Maintenance Program
- Intake Cooling Water Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Periodic Surveillance and Preventive Maintenance Program, the Boric Acid Wastage Surveillance Program, and the Systems and Structures Monitoring Program are credited with managing the aging effects of several components in different structures and systems, and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER. The Intake Cooling Water Inspection Program is credited with managing the aging effects of several components in auxiliary systems, and is, therefore, considered to be a system-specific AMP. The staff's evaluation of the Intake Cooling Water Inspection Program is described in Section 3.3.0.2 of this SER.

The Systems and Structures Monitoring Program provides for visual inspection of external surfaces of the components for evidence of degradation or leakage. The description of this program is provided in Section 3.2.14, "Systems and Structures Monitoring Program," of Appendix B to the LRA. The detailed evaluation of this program is presented in Section 3.0.5.10 of this SER. The applicant relies on detection of leakage for managing loss of material on the inside surface of several components exposed to raw water. The applicant has performed evaluations that show that through-wall leakage equivalent to a sheared 3/4 inch instrument line, and an additional 100 gpm opening from another location, will not reduce the ICW flow to the CCW heat exchangers below design requirements. The staff's concern is that the presence of leakage from a component, however, would indicate that the component has lost its ability to perform its intended function, i.e., pressure boundary. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-3, the applicant to justify why the use of this program alone is adequate for managing loss of material at the inside surface of the components exposed to raw water. In its response dated November 27, 2002, the applicant stated that in addition to leak detection, it will employ the Intake Cooling Water System Inspection Program (LRA Appendix B, Subsection 3.2.20, page B-43) in addition to the Systems and Structures Monitoring Program (LRA Appendix B, Subsection 3.2.14, page B-57) for managing the aging effect of loss of material for valves, piping, and fittings at selected locations of ICW. Although the ICW crawl-through inspections do not include inspection of small bore piping components due to access limitations, the crawl-through inspections do inspect the connections between the small bore piping and large bore piping, which are the limiting locations for the small bore piping components. The applicant provides the following explanation of why these connections are the limiting locations. Originally the small-diameter piping was epoxy-coated carbon steel piping. This piping has leaked in the past because of its exposure to salt water and resulting loss of material due to corrosion at the inside surface. As a result, the applicant has replaced 75 percent of this small-diameter carbon steel piping with piping constructed of corrosion-resistant materials (e.g., monel, bronze, aluminum bronze). However, the connections of the replaced piping with the large bore piping have not been replaced. These connections are still the original epoxy-coated carbon steel. Therefore, these connections remain the bounding locations for the replaced piping.

In addition, the applicant provides the following justification for why the leak detection is adequate to maintain the intended function of the ICW system. Maintenance history shows that localized failures of cement lining result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage, which provides adequate time for repairs before the system function is degraded. For small valves, piping, and fittings, leakage does not affect the system function because the small size of these components limits the leakage. Plant operators walk down the ICW system as part of normal shift activities, and would note any leaks that were present. When leaks are identified, they are immediately documented under the corrective action program and receive prompt engineering evaluation and corrective actions. The operating and maintenance history of this equipment demonstrates that leakage for this equipment has not been significant. Thus, the applicant concludes that the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of ICW.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.9-3 clarifies and satisfactorily resolves this item because the applicant has demonstrated that the leakage detection, along with the inspections of all the carbon steel connections between the small- and large-diameter piping, would provide adequate management for loss of material at the inside surface of the small-diameter piping without degrading the ICW system function.

Based on its review of LRA Table 3.3-9, the staff concludes that the above identified AMPs will effectively manage the aging effects of the ICW system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9.3 Conclusions

The staff reviewed the information in Section 2.3.3.9 and Table 3.3-9 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the ICW system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the ICW system, as required by 10 CFR 54.21(d).

3.3.10 Miscellaneous Bulk Gas Supply System

3.3.10.1 Summary of Technical Information in the Application

The common miscellaneous bulk gas supply system consists of the hydrogen, carbon dioxide, and nitrogen systems. Various storage facilities and associated components are provided for Units 1 and 2 for supplying hydrogen, carbon dioxide, and nitrogen for plant operation. Hydrogen is stored in tube trailers and in bottles in the hydrogen storage facilities. The hydrogen storage facilities and distribution system are designed to comply with the Occupational Safety and Health Administration (OSHA) requirements. Carbon dioxide is stored in bottles in the gas storage building, which is located adjacent to the hydrogen storage facility. The carbon dioxide system is designed to OSHA requirements. The nitrogen system supplies low and high-pressure nitrogen to various systems and vessels which require cover gas. Bulk storage facilities for nitrogen are provided by a low-pressure nitrogen dewar with two compressors and a high-pressure tube trailer. In addition, a bank of cylinders supplies nitrogen gas for the nuclear steam supply system. The storage facility and the distribution piping of the nitrogen system are designed to meet the OSHA requirements. Details of the common miscellaneous bulk gas supply system are described in Unit 1 UFSAR Section 9.3.1.

3.3.10.1.1 Aging Effects

Components of the miscellaneous bulk gas supply system are described in Section 2.3.3.10 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-10, page 3.3-65, of the LRA lists individual components of the system including vessel, piping/fitting, tubing/fitting, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal environment of air/gas and external environments of indoor not-air-conditioned with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to indoor not-air-conditioned and borated water leaks. Carbon steel components are identified as being subject to the internal environment of air/gas with no aging effects identified.

3.3.10.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the miscellaneous bulk gas supply system.

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the miscellaneous bulk gas supply system will be adequately managed by these AMPs for the period of extended operation.

3.3.10.2 Staff Evaluation

The applicant described its AMR of the miscellaneous bulk gas supply system for license renewal in Section 2.3.3.10 and Table 3.3-10. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the miscellaneous bulk gas supply system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.10, Table 3.3-10, and the applicable sections in Appendix C of the LRA. The aging effects that result from contact of the miscellaneous bulk gas supply system SSCs to the environments described in Section 2.3.3.10 and Table 3.3-10 are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.10.2.2 Aging Management Programs

In Table 3.3-10 of the LRA, the applicant credited the following AMPs for managing the aging effects in the miscellaneous bulk gas supply system.

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-10, the staff concludes that the above identified AMPs will effectively manage the aging effects of the miscellaneous bulk gas supply system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10.3 Conclusions

The staff reviewed the information in Section 2.3.3.10 and Table 3.3-10 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the miscellaneous bulk gas supply systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the miscellaneous bulk gas supply systems as required by 10 CFR 54.21(d).

3.3.11 Primary Makeup Water

3.3.11.1 Summary of Technical Information in the Application

Primary makeup water provides treated, demineralized water for makeup to various systems throughout the St. Lucie Units 1 and 2 plants. Details of the primary makeup water system are described in Unit 1 UFSAR Section 9.2.5 and Unit 2 UFSAR Section 9.2.3.

3.3.11.1.1 Aging Effects

Components of the primary makeup water system are described in Section 2.3.3.11 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-11, pages 3.3-66 through 3.3-69, of the LRA lists individual components of the system including carbon steel tanks, stainless steel pumps, valves (pressure boundary only), piping, tubing, fittings, vortex breaker (Unit 2 only), orifices (Unit 2 only), nickel alloy piping (Unit 1 only), copper alloy valves, hose-station fittings, hose-station nozzles (Unit 2 only), and rubber expansion joints (Unit 2 only). Stainless steel components are identified as subject to loss of material aging effects due to exposure to treated water environments. Carbon steel components exposed to treated water and air/gas environments are subject to loss of material aging effects. Rubber components exposed to treated water and other environments are subject to cracking aging effects. Exposure of nickel alloy and copper alloy components to treated water environment has loss of material aging effects. Exposure of copper alloy components to air/gas environment has no aging effects.

3.3.11.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the primary makeup water system.

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the primary makeup water system will be adequately managed by these AMPs for the period of extended operation.

3.3.11.2 Staff Evaluation

The applicant described its AMR for the primary makeup water system for license renewal in Section 2.3.3.11 and Section 3.3, Table 3.3-11. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the primary makeup water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.11, Table 3.3-11, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.11-1, the applicant to provide additional information to clarify whether hardening is an applicable aging effect for the rubber materials of the expansion joints in the primary makeup water system, and to discuss how, if applicable, this aging effect will be managed. In its response dated September 26, 2002, the applicant stated that *Marks' Standard Handbook for Mechanical Engineers* (Tenth Edition, page 6-147) describes rubber that is exposed to an outdoor environment (air and sun) may become hard and brittle (embrittlement as defined on Page C-15 of LRA Appendix C, Section 5.2). The aging effect resulting from embrittlement and hardening is cracking. The applicant also stated that cracking is identified in LRA Table 3.3-11 as an aging effect requiring management for the rubber expansion joints of the Unit 2 primary makeup water system. This aging effect is adequately managed by the Systems and Structures Monitoring Program.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the applicant has identified cracking as an applicable aging effect resulting from embrittlement and hardening for the rubber expansion joints of the Unit 2 primary makeup water system, and this aging effect is managed by the Systems and Structures Monitoring Program.

The applicant identified loss of material as an applicable aging effect for the carbon steel primary water storage tank (Unit 2 only) because of the humid air due to water in the lower portion of the tanks. However, the applicant did not identify any aging effects for copper alloy components exposed to the internal air/gas environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.11-2, the applicant to describe the composition of the internal air/gas environment to which the fittings and nozzles of the hose station of Unit 2 are exposed, and to specify the level of humidity of this particular environment. The applicant was also requested to clarify whether loss of material is an applicable aging effect and to discuss how, if applicable, this aging effect will be managed.

In its response dated September 26, 2002, the applicant stated that the fittings and nozzles of the Unit 2 hose stations are exposed to internal air/gas environments consisting of the external environment (i.e., indoor not-air-conditioned or containment air). These environments are defined in LRA Table 3.0-2 (page 3.0-3). As discussed in LRA Appendix C, Section 5.1 (page C-11), loss of material is not an applicable aging effect for copper alloy materials exposed to these environments. The applicant also stated that this conclusion is supported by a review of St. Lucie plant-specific operating experience, which did not identify loss of material as an aging effect requiring management for these components.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the plant-specific operating experience demonstrates that loss of material is not an applicable aging effect for copper alloy material exposed to the environment described in RAI 3.3.11-2.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-4 pertaining to the chloride-related corrosion in the embedded/encased stainless steel piping/fitting. The staff's evaluation of the applicant's response is documented in Section 3.3.17.4 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the primary makeup water system SSCs to the environments described in

Section 2.3.3.11 and Table 3.3-11, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.11.2.2 Aging Management Programs

In Table 3.3-11 of the LRA, the applicant credited the following AMPs for managing the aging effects in the components in the primary makeup water system.

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-11, the staff concludes that the above identified AMPs will effectively manage the aging effects of the primary makeup water system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11.3 Conclusions

The staff reviewed the information in Section 2.3.3.11 and Table 3.3-11 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the primary makeup water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the primary makeup water system, as required by 10 CFR 54.21(d).

3.3.12 Sampling System

3.3.12.1 Summary of Technical Information in the Application

The sampling system provides the means to obtain samples from the RCS and auxiliary systems for chemical and radiological tests of boron concentration, fission and corrosion product levels, chloride, pH, and conductivity levels. A high pressure and high temperature sample from the hot leg of the RCS is routed to the sampling system where it is cooled to 120 °F or less and 25 psig in pressure in a sample heat exchanger. Samples are also obtained from the shutdown cooling system and the chemical and volume control system at a temperature of 120 °F and a pressure of approximately 25 psig. The sampling room is located in the reactor auxiliary room. The major components of the sampling system are constructed from stainless steel to minimize any potential corrosion problems. The major components of the sampling system include heat exchanger, sample vessel, sink and hood, and delay line. The sample delay line consists of 150 of tubing to allow for the decay of radionuclides of the reactor coolant. Details of the sampling system are described in Unit 1 UFASR Section 9.3.2 and Unit 2 UFAR Section 9.3.2.

3.3.12.1.1 Aging Effects

Components of the nuclear sampling system are described in Section 2.3.3.12 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-12, page 3.3-70, of the LRA lists individual components of the system including valves, tubing/fittings, and bolting. An internal environment of borated water causes the aging effect of loss of material and cracking in stainless steel components. Stainless steel components are identified as being subject to the external environments of indoor not-air-conditioned and containment air, and are subject to no aging effects. Carbon steel bolting is identified as being subject to the external environments of indoor not-air-conditioned and containment air, and are subject to no aging effects. Carbon steel bolting is identified as being subject to the external environments of borated water with aging effects of loss of material and cracking identified.

3.3.12.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the sampling system.

- Chemistry Control Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the sampling system will be adequately managed by these AMPs for the period of extended operation.

3.3.12.2 Staff Evaluation

The applicant described its AMR of the sampling system for license renewal in Section 2.3.3.12 and Section 3.3, Table 3.3-12. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the sampling system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.12, Table 3.3-12, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the sampling system SSCs to the environments described in Section 2.3.3.12 and Table 3.3-12 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.12.2.2 Aging Management Programs

In Table 3.3-12 of the LRA, the applicant credited the following AMPs for managing the aging effects in the sampling system.

- Chemistry Control Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-12, the staff concludes that the above identified AMPs will effectively manage the aging effects of the sampling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12.3 Conclusions

The staff reviewed the information in Section 2.3.3.12 and Table 3.3-12 of the LRA, and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the sampling system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the sampling system, as required by 10 CFR 54.21(d).

3.3.13 Service Water System

3.3.13.1 Summary of Technical Information in the Application

The service water system supports fire protection and supplies water to the plant shutdown stations, decontamination facilities, and portable water system. Details of the service water system are described in Unit 1 UFSAR Section 9.2.6 and Unit 2 UFSAR Section 9.2.4.

3.3.13.1.1 Aging Effects

Components of the service water system are described in Section 2.3.3.13 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-13, pages 3.3-71 through 3.3-72, of the LRA lists individual components of the system including yard sump pump, valves, piping/fittings, and bolting. Loss of material is identified as an aging effect for stainless steel components exposed to internal environment of raw water—drains. No aging effect is identified for stainless steel components exposed to internal environment of raw water—city water. Loss of material is identified as an aging effect for copper alloy and galvanized carbon steel components exposed to internal environment of air/gas (wetted). Loss of material is identified as an aging effect for stainless steel components exposed to external environment of raw water—drains. Loss of material and cracking are identified as aging effects for stainless steel components exposed to external environment of outdoor (ECCS pipe tunnel). No aging effect is identified for stainless steel, copper alloy, galvanized carbon steel, and carbon steel components exposed to external environment of outdoor and indoor not-air-conditioned. Loss of mechanical closure integrity is identified for carbon steel bolting exposed to external environment of borated water leaks.

3.3.13.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the service water system.

- Periodic Surveillance and Preventive Maintenance Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the service water system will be adequately managed by these AMPs for the period of extended operation.

3.3.13.2 Staff Evaluation

The applicant described its AMR of the service water system for license renewal in Section 2.3.3.13 and Table 3.3-13. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the service water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.13, Table 3.3-13, and the applicable sections in Appendix C to the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the service water system SSCs to the environments described in Section 2.3.3.13 and Table 3.3-13, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.13.2.2 Aging Management Programs

In Table 3.3-13 of the LRA, the applicant credited the following AMPs for managing the aging effects in the service water system.

- Periodic Surveillance and Preventive Maintenance Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

During its review of the information in Section 2.3.3.13 and Table 3.3-13 of the LRA, the staff determined that additional information was needed to complete its review. In Table 3.3.13-1, the applicant credited the Periodic Surveillance and Preventive Maintenance Program for managing loss of material for the yard sump pump exposed to internal environment of raw water—drains. In Appendix B of the LRA, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program provides visual inspection of component surfaces. By letter dated July 1, 2002, the staff requested, in RAI 3.3.13-1, the applicant to describe how visual inspection is conducted for the submerged surfaces of the sump pump.

In its response dated September 26, 2002, the applicant stated that the total sump depth for the pump subject to inspection is 2.5 ft. Dewatering of that sump will be performed, if necessary, to perform a visual inspection. On the basis of its review, the staff finds the applicant's response to RAI 3.3.13-1 acceptable because it clarifies how visual inspection is conducted for the submerged surface of the sump pump by the Periodic Surveillance and Preventive Maintenance Program, as requested by the staff.

Based on its review of LRA Table 3.3-13, and the information provided in the applicant's response to RAI 3.3.13-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the service water system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13.3 Conclusions

The staff reviewed the information in Section 2.3.3.13 and Table 3.3-13 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the service water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the service water system, as required by 10 CFR 54.21(d).

3.3.14 Turbine Cooling Water System (Unit 1 only)

3.3.14.1 Summary of Technical Information in the Application

Turbine cooling water system (Unit 1 only) is a closed-loop system used to remove heat from the turbine and other components in the power cycle, including the instrument air compressors. Details of turbine cooling water system are described in Unit 1 UFSAR Section 9.2.4.

3.3.14.1.1 Aging Effects

Components of the turbine cooling water system are described in Section 2.3.3.14 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-14, pages 3.3-73 through 3.3-74, of the LRA lists individual components of the system including stainless steel thermowells, carbon steel tanks, pumps, air fan cooler heads, valves (pressure boundary only), piping, fittings and bolting (mechanical closures), brass instrument air fan cooler tubes and instrument air fan cooler fins, and glass sight glasses. Stainless steel components are identified as subject to loss of material aging effects due to exposure to treated water. Exposure of stainless steel components to non-air-conditioned environment has no aging effects. Carbon steel components exposed to treated water and non-air-conditioned environment are subject to the aging effect of loss of material. Exposure of carbon steel components to air/gas environment has no aging effects. Exposure of carbon steel bolting components to non-air-conditioned environment has no aging effect. Brass components exposed to treated water and non-air-conditioned environments are subject to loss of material and fouling aging effects. Exposure of glass components to treated water and non-air-conditioned environments has no aging effects.

3.3.14.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the turbine cooling water system.

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the turbine cooling water system will be adequately managed by these AMPs for the period of extended operation.

3.3.14.2 Staff Evaluation

The applicant described its AMR for the turbine cooling water system for license renewal in Section 2.3.3.14 and Section 3.3, Table 3.3-14. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the turbine cooling water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.14.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.14, Table 3.3-14, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

The component in the turbine cooling water system exposed internally to the air/gas environment is the instrument air compressor cooling water head tank (carbon steel). Instrument air upstream of the air dryers is annotated as "wetted." The applicant did not identify any aging effects for carbon steel instrument air compressor cooling water head tank exposed to the internal air/gas environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.14-1, the applicant identify the composition of the internal air/gas environment to which the Unit 1 instrument air compressor cooling water head tank is exposed, and specify the level of humidity of this particular environment. The applicant was also requested to clarify whether the tank wall is subjected to a changing wetting environment as the water level changes. In addition, the staff requested the applicant discuss whether loss of material is an applicable aging effect for this component.

In its response dated September 26, 2002, the applicant stated that the instrument air cooling water head tank is a small-diameter tank with a hinged access cover in its top. This tank is normally filled with turbine cooling water to a level approximately 1 inch from the top of the tank. Turbine cooling water is chemically controlled and is treated with a corrosion inhibitor. The tank is vented and, therefore, the small air space above the normal water level of the tank is exposed to atmospheric conditions. The tank is internally coated to protect the carbon steel surface from general corrosion. A visual inspection of the tank performed as part of the AMR did not identify any significant coating degradation or signs of general corrosion. Additionally, even if loss of material due to general corrosion were to occur in this portion of the tank, it would not impact the component or system intended function. Therefore, there are no aging effects requiring management for the internal surfaces of this tank exposed to an air/gas environment.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.14-1 is reasonable and adequate because the applicant has provided the detailed information on the tank and its environment, as well as the results of the inspection performed as part of the AMR that did not identify any significant coating degradation or signs of general corrosion.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the turbine cooling water system SSCs to the environments described in

Section 2.3.3.14 and Table 3.3-14, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.14.2.2 Aging Management Programs

In Table 3.3-14 of the LRA, the applicant credited the following AMPs for managing the aging effects for the components in the turbine cooling water system.

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program

These AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-14, the staff concludes that these AMPs will effectively manage the aging effects of the turbine cooling water system, and there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.14.3 Conclusions

The staff reviewed the information in Section 2.3.3.14 and Table 3.3-14 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the turbine cooling water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the service water system, as required by 10 CFR 54.21(d).

3.3.15 Ventilation

3.3.15.1 Summary of Technical Information in the Application

Ventilation provides heating, ventilation, and air conditioning to various buildings and rooms/ areas throughout the plant. Ventilation includes the following eight subsystems—control room air conditioning, emergency core cooling system area ventilation, fuel handling building ventilation (Unit 2 only), intake structure ventilation (Unit 2 only), miscellaneous ventilation (Unit 1 only), reactor auxiliary building electrical and battery room ventilation, reactor auxiliary building main supply and exhaust, and shield building ventilation. Details of the ventilation system are described in Unit 1 UFSAR Sections 6.2 and 9.4, and Unit 2 UFSAR Sections 6.2 and 9.4.

3.3.15.1.1 Aging Effects

Components of the ventilation system are described in Section 2.3.3.15 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-15, pages 3.3-75 through 3.3-88, of the LRA, lists individual components of the system including valves (pressure boundary only), filter housings, heat exchangers, flexible connections, ducts, demisters, thermowells, orifices, structural supports, piping, tubing, and fittings. The copper-nickel heat exchanger components and carbon steel piping/fittings and valves (Unit 2 only) of the control room air conditioner are internally exposed to treated water. The corresponding aging effects requiring management are loss of material and fouling. The stainless steel piping/fittings (Unit 2 only) of the control room air conditioner are internally exposed to treated water. Their corresponding aging effect requiring management is loss of material. The carbon steel components of the ventilation system are internally exposed to air/gas environment (atmospheric air or outside air with uncontrolled humidity and temperature). The corresponding aging effect requiring management is loss of material. The carbon steel components of the ventilation system are externally exposed to indoor not air-conditioned environment or borated water leaks. The corresponding aging effect requiring management is loss of material. The galvanized carbon steel components of the reactor auxiliary building electrical and battery room ventilation system are internally exposed to outside air with uncontrolled humidity and temperature (one type of air/gas environment). The corresponding aging effect requiring management is loss of material. The galvanized carbon steel ducts in the ventilation system are externally exposed to borated water leaks. The corresponding aging effect requiring management is loss of material. The flexible connections made of rubber-coated cloth are internally exposed to air/gas environment and externally exposed to indoor not-air-conditioned environment. The corresponding aging effect requiring management is cracking. The carbon steel bolting (mechanical closure) is externally exposed to borated water leaks. The corresponding aging effects requiring management is loss of mechanical integrity and loss of material.

3.3.15.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the ventilation system.

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concludes that the effect of aging associated with the components of the ventilation system will be adequately managed by these AMPs for the period of extended operation.

3.3.15.2 Staff Evaluation

The applicant describes its AMR of the eight subsystems of the ventilation system for license renewal in Section 2.3.3.15 and Section 3.3, Table 3.3-15. The process of identification of the aging effects is summarized in Appendix C to the LRA, and a description of the AMPs is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ventilation system will be adequately managed for the extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.15, Table 3.3-15, and the applicable sections in Appendix C to the LRA. During its review, the staff determined that additional information was needed to complete its review.

For control room air conditioning subsystem, the applicant has identified loss of material as an applicable aging effect for carbon steel filter housing internally exposed to air/gas environment, but not for other carbon steel components (e.g., valves and piping/fittings) exposed to the same environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.15-1, the applicant to explain this discrepancy. In its response dated November 27, 2002, the applicant provided the following information. The carbon steel valves and piping/fittings identified in LRA Table 3.3-15 exposed to an air/gas environment are associated with Unit 1 control room air conditioning outside air intake system. The internal air/gas environment for the piping and valves is outside air. As discussed in LRA Appendix C, Section 5.1 (page C-11), carbon steel is considered susceptible to loss of material due to general corrosion in this environment. As such, the AMR of these components evaluated the potential impact of this aging effect on component intended function.

Unlike the carbon steel ventilation housings, which are constructed of heavy gauge sheet metal, the carbon steel piping evaluated here is Schedule 40 and has a nominal thickness of 0.280 inches. The valves, which are wafer-type butterfly valves, have a body thickness greater than 1 inch. The applicant used the conservative corrosion rates for steel exposed to "inland environment" from Tables 6-1 and F-1 of the (MCIC Report, "Corrosion of Metals in Marine Environment" calculate the worst-case average loss of wall thickness of 76 mils (3 mils/yr x 8 yrs + 1 mil/yr x 52 yrs) over the life of the plant. The applicant stated that the average reduction in thickness is estimated because the aging mechanism of concern for the internal surfaces of the control room air conditioning outside intake valves/piping/fittings is general corrosion. The applicant further stated that due to the location of these components and their limited air exchange with the environment, aggressive chemical species will not be present and significant pitting corrosion is not expected. The applicant stated that the inland environment data are applicable based upon expected conditions for the air space inside the control room air conditioning intake components. The control room air conditioning outside intake line is located inside the reactor auxiliary building and is normally isolated. Thus, high humidity of inland tropical environment without aggressive species, such as chlorides, is applicable.

The applicant further stated that the corrosion rate decreases with time due to the buildup of an oxidation layer, which will tend to provide some protection of the bare metal underneath. Thus, based upon this worst-case corrosion rate, the remaining piping wall thickness is 0.204 inches. Since this portion of the ventilation system is nonpressurized, the remaining wall thickness must only address structural loads, and it is concluded that adequate corrosion allowance exists for these components. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the control room air conditioning outside air intake (which are exposed to an air/gas environment) is not an aging effect requiring management.

On the basis of its review, the staff finds the applicant's conclusion that loss of material due to corrosion is not an aging effect for these components that requires management acceptable because the applicant demonstrated that these components have sufficient corrosion allowance.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the ventilation system SSCs to the environments described in Section 2.3.3.15 and Table 3.3-15, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.15.2.2 Aging Management Programs

In Table 3.3-15 of the LRA, the applicant credited the following AMPs for managing the aging effects in the ventilation system.

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

The description of the Periodic Surveillance and Preventive Maintenance Program is provided in Section 3.2.11, Periodic Surveillance and Preventive Maintenance Program, of Appendix B to the LRA. The staff's detailed evaluation of this program is presented in Section 3.0.5.9 of this SER. The Periodic Surveillance and Preventive Maintenance Program provides for visual inspection, examination of component surfaces, and leakage inspections to determine the existence of internal corrosion or cracking. Therefore, it appears that the applicant relies on detection of leakage for managing loss of material on the inside surface of several components exposed to air/gas environment. The presence of leakage from a component, however, would indicate that the component has lost its ability to perform its intended function, i.e., pressure boundary integrity. By letter dated July 1, 2002, the staff requested, in RAI 3.3.15-2, the applicant explain how the component's capability to perform its intended function is maintained. In its response dated September 26, 2002, the applicant stated that loss of material in the ventilation system carbon steel components is managed by visual inspections and examinations of the plenums, housings, shells, and supports. The applicant further stated that leak inspection is not credited for aging management of the ventilation systems listed in LRA Table 3.3-15.

On the basis of its review, the staff finds the applicant's response to RAI 3.3.15-2 acceptable because the applicant demonstrated that pressure boundary integrity of the ventilation system components, which are internally exposed to air/gas environment, is maintained by visual inspections and examinations of the Periodic Surveillance and Preventive Maintenance Program.

Based on its review of LRA Table 3.3-15, the staff concludes that the above identified AMPs will effectively manage the aging effects of the ventilation system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15.3 Conclusions

The staff reviewed the information in Section 2.3.3.15 and Table 3.3-15 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the ventilation systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the ventilation systems, as required by 10 CFR 54.21(d).

3.3.16 Waste Management

3.3.16.1 Summary of Technical Information in the Application

The waste management collects, monitors, and processes potentially radioactive reactor plant wastes prior to release or removal from the plant site. The waste management system consists of three subsystems—liquid, gaseous, and solid waste management. Liquid wastes include those from the laboratory sink drains, decontamination area drains, floor drains, building sumps, and contaminated showers. The solid waste management system collects, controls, processes, packages, handles, and temporarily stores solid radioactive waste. The solid waste management system consists of spent resin tank, piping, and valves connecting to a shipping container and to the ECCS sump for resin drain/dewatering operations. Details of the waste management system are described in Unit 1 UFSAR Sections 9.3.3, 11.2.2, 11.3.2, and 11.5.2, and Unit 2 UFSAR, Sections 9.3.3, 11.2.2, 11.3.2, and 11.4.2.

3.3.16.1.1 Aging Effects

Components of the waste management system are described in Section 2.3.3.16 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-16, pages 3.3-89 through 3.3-91, of the LRA, lists individual components of the system including valves, piping/fittings, cleanout plugs, strainers, orifices, and bolting.

The components in the waste management system are fabricated from nickel alloy, carbon steel, bronze, stainless steel, and copper alloy, and are exposed to internal environment of air/gas. These components include valves, piping/fitting, cleanout plugs, strainers, strainer element, and orifices. Loss of material is identified as an applicable aging effect for the carbon steel cleanout plugs exposed to the internal environment of air/gas. The applicant stated that the internal air/gas environment in the cleanout plugs is outside air with uncontrolled humidity and temperature. No aging effect is identified for the nickel alloy, carbon steel, bronze, stainless steel, and copper alloy components exposed to internal air/gas environment of inside air with controlled humidity and temperatures. No aging effect is identified for the stainless steel components exposed to internal environment of raw water—drains or air/gas. The raw water—drains is the fluids collected in building drains. The fluids can be treated water (primary, secondary, borated, or other), raw water (cooling canals or city water), fuel oil, or lubricating oil.

Loss of material is identified for the carbon steel components exposed to external environments of indoor not-air-conditioned or containment air. The external indoor not air-conditioned environment is atmospheric air, a temperature of 104 °F maximum, 73 percent average humidity, and no exposure to weather. The external containment air environment is atmospheric air, a temperature of 120 °F maximum, 73 percent average humidity, and no exposure to weather. Loss of material and loss of mechanical closure integrity are identified as the applicable aging effects for carbon steel components exposed to external environment of borated water leaks. No aging effect is identified for the stainless steel, nickel alloy, bronze, and copper alloy components exposed to external environments of indoor not-air-conditioned or containment air. No aging effect is identified for the stainless steel components exposed to external environment of embedded/encased in concrete.

3.3.16.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the waste management system:

- System and Structure Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components of the waste management system will be adequately managed by these AMPs for the period of extended operation.

3.3.16.2 Staff Evaluation

The applicant described its AMR of the waste management system for license renewal in Section 2.3.3.16 and Section 3.3, Table 3.3-16. The process of identification of the aging effects is summarized in Appendix C to the LRA, and a description of the AMPs is provided in Appendix B to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the waste management system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.16, Table 3.3-16, and the applicable sections in Appendix C to the LRA. During its review, the staff determined that additional information was needed to complete its review.

In Table 3.3-13 of the LRA, the applicant identifies loss of material as an applicable aging effect for the stainless steel yard sump pump of the service water system which is exposed to an internal environment of raw water—drains, but not for the stainless steel valves and piping/fittings exposed to the same environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.16-1, the applicant explain why loss of material is not identified as an applicable aging effect for the stainless steel valves and piping/fittings of the waste management system, which are exposed to the same environment of raw water—drains.

In its response dated September 26, 2002, the applicant stated that the stainless steel yard sump is located in the pipe trench connected to the Unit 2 CCW structure, and thus is exposed to raw water consisting of drainage run off. This water may be high in chlorides or other contaminants and, therefore, may create an aggressive environment for corrosion. On the other hand, the subject portion of the waste management system drains consists of that portion of the system from the reactor coolant drain tank outlet which penetrates containment. These drains are from in-containment sources such as RCS loop drains and other inputs to the reactor coolant drain tank. A review of St. Lucie plant-specific operating experience of waste management did not identify any instances of loss of material for this system. In addition, a volumetric inspection performed as part of the AMR for stainless steel waste management piping in the RABs identified no loss of material for these portions of the system. Therefore, loss of material is not an aging effect requiring management for the stainless steel valves and piping/fittings of waste management exposed to the environment of raw water—drains.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.16-1 clarifies and satisfactorily resolves the item because the applicant demonstrated that environment of raw water—drains in the waste management system is less aggressive and loss of material is not an applicable aging effect which is validated by the plant operating experience.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the waste management system SSCs to the environments described in Section 2.3.3.16 and Table 3.3-16, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.16.2.2 Aging Management Programs

In Table 3.3-16 of the LRA, the applicant credited the following AMPs for managing the aging effects in the waste management system.

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-16, the staff concludes that the AMPs identified above will effectively manage the aging effects of the waste management system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16.3 Conclusions

The staff reviewed the information in Section 2.3.3.16 and Table 3.3-16 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the waste management system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the waste management system, as required by 10 CFR 54.21(d).

3.3.17 General AMR Issues

This section discusses the staff's evaluation on seven general AMR issues that are applicable to components in several auxiliary systems included in Section 3.3 of the LRA.

3.3.17.1 Aging Effects for Closure Bolting

The applicant did not identify loss of material and cracking for some closure boltings in several auxiliary systems included in Section 3.3 of the LRA. Since closure bolting may be exposed to warm air, moisture, and leaking fluid (boric acid) environments, it may be subject to the aging effects of loss of material and cracking. By letter dated July 1, 2002, the staff requested, in RAI 3.3-1, the applicant justify why the LRA excludes the aging effects, including loss of material and cracking, for carbon steel, stainless steel, bronze, brass, and copper boltings in the following systems and for the environments to which they are exposed. The environments include outdoor, indoor not-air-conditioned, containment, and buried environments. The systems that should be considered are instrument air, component cooling water, diesel generator, intake cooling water, primary water makeup, service water system, turbine cooling water (Unit 1 only), ventilation, sampling, and steam and power conversion. The staff also requested the applicant provide a summary of the plant-specific operating experience associated with the degradation of bolting.

In its response dated September 26, 2002, the applicant stated that as discussed in LRA Appendix C, Subsection 5.4 (page C-16), "Loss of Mechanical Closure Integrity," the loss of bolting material and cracking were evaluated for their effects on mechanical closure integrity. Only loss of bolting material associated with aggressive chemical attack (e.g., borated water leaks) was determined to require aging management. The closure boltings in instrument air, CCW, ICW, primary water, service water, ventilation, and SPCS credit the Boric Acid Wastage Surveillance Program for managing loss of mechanical closure integrity due to boric acid corrosion. The emergency diesel generators and turbine cooling water are not subject to loss of material due to boric acid corrosion based upon the distance of those systems to borated water sources.

The applicant further stated that although the LRA identifies bolting (mechanical closures) material as carbon steel, the actual bolting material for St. Lucie piping and components is a low-alloy steel ASTM A193, Grade B7. This material provides increased corrosion resistance over carbon steel. Additionally, bolting is typically in a dry (non wetted) environment and is coated with a lubricant. At St. Lucie, it is a standard maintenance practice to clean and lubricate bolting prior to assembly of components. The applicant also stated that lubrication of bolting is addressed in general maintenance bolting procedures. When the bolting is associated with a system that operates at a temperature greater than 212 °F (such as main steam, auxiliary steam, main feedwater, and SG blowdown) or is located in an air-conditioned environment (such as some ventilation system components), it further eliminates the presence of moisture and potential for corrosion. Although bolting located in outdoor, indoor not-air-conditioned, and containment environments is subject to an average humidity level of 73 percent (as described in LRA Appendix C, Section 4.2, page C-9), a review of St. Lucie plant-specific operating experience only identified a few cases of corrosion of bolting. These cases were associated with nonpressure boundary valve gland bolting with the corrosion attributed to packing leaks. It is the plant policy to minimize operation with valve packing leaks, and thus, packing leaks are identified and repaired on a timely basis. As such, loss of material due to general or pitting corrosion is not an applicable aging effect for low-alloy steel bolting. The applicant also stated that pitting of stainless steel bolting material has not been experienced at St. Lucie.

The applicant further stated that as indicated in LRA Appendix C, Section 1.0, page C-3, FPL utilized the industry guidance developed by the Babcock and Wilcox Owners Group in determining the aging effects requiring management. As part of the development of this industry guidance document, a review of industry data (including other saltwater nuclear plant sites) was performed. Industry data reviewed included Nuclear Plant Reliability Data System and NRC generic publications. The results of this review of industry operating experience did not identify loss of material due to general corrosion or pitting as an aging effect requiring management for bolting. Therefore, the applicant concluded that apart from aggressive chemical attack, loss of bolting material due to corrosion is not an applicable aging effect for the systems identified in RAI 3.3-1.

In addition, the applicant stated that as discussed in LRA Appendix C, Subsection 5.4, page C-16, the potential for SCC of bolting materials has been addressed at St. Lucie as part of corrective actions to NRC IE Bulletin 82-02. These actions have been effective in eliminating this aging effect. A review of St. Lucie plant-specific operating experience identified no instances of bolting degradation due to SCC. Additionally, a review of NRC generic communications did not identify any recent bolting failures attributed to SCC. Therefore, the applicant concluded that cracking of bolting material due to SCC is not an aging effect requiring management for the systems identified in RAI 3.3-1. The applicant further noted that this position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the information provided by the applicant included the distance of the systems to borated water sources and identified the type of material used for manufacturing the bolts as low-alloy steel ASTM A193, Grade B7. In addition, the industry and St. Lucie plant-specific operating experience demonstrated that loss of material and cracking are not the applicable aging effects for closure bolting.

3.3.17.2 Boric Acid Corrosion

By letter dated July 1, 2002, the staff requested, in RAI 3.3-2, the applicant clarify whether the following components are likely to be externally exposed to borated coolant leaking from any adjacent systems or components.

- CCW system carbon steel surge tanks, pump bodies, and heat exchanger shells
- demineralized makeup water system (any component)
- instrument air system carbon and galvanized steel components, such as instrument air receivers, bolting, dryers, and compressor cooler shells
- ICW system carbon steel basket strainers and valve bodies
- turbine cooling water (Unit 1 only) system carbon steel components

In its response dated September 26, 2002, the applicant stated that the following components are not in proximity to any systems which contain borated water and therefore are not exposed to borated water leaking from any adjacent systems or components.

- CCW carbon steel surge tanks, pump bodies, and heat exchanger shells
- instrument air receivers, bolting, dryers, and compressor cooler shells and associated components
- ICW carbon steel basket strainers and valve bodies
- turbine cooling water carbon steel components

Some instrument air components may be exposed to borated water leakage from adjacent systems or components (LRA Table 3.3-8, pages 3.3-56, 3.3-57, and 3.3-58).

Loss of material due to boric acid corrosion of instrument air carbon steel components exposed to borated water leaks is managed by the Boric Acid Wastage Surveillance Program.

The applicant further stated that demineralized makeup water components are stainless steel and thus not susceptible to boric acid wastage. The demineralized makeup water bolting in the scope of license renewal is not in proximity to any systems that contain borated water and therefore cannot be exposed to borated water leaking from any adjacent systems or components.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the information provided by the applicant clarifies that these components are not exposed to boric acid leaking and, therefore, boric acid corrosion is not an applicable aging effect.

3.3.17.3 Chloride-Related Corrosion in Embedded/Encased Carbon Steel Piping/Fitting

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 percent average humidity, and exposure to weather, including precipitation and wind. 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, the applicant did not identify any aging effects for carbon steel components in the emergency cooling canal system and the ICW system exposed to an embedded/encased environment.

By letter dated July 1, 2002, the staff requested, in RAI 3.3-3, the applicant clarify the environment to which the concrete with embedded/encased carbon steel piping/fitting is exposed. The applicant was also requested to explain why the above described aging process is not applicable to St. Lucie, to discuss the plant operating history concerning carbon steel components exposed to an embedded/encased environment, and to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that the emergency cooling canal embedded/encased piping listed in LRA Table 3.3-5 is actually bolted to the concrete and is therefore not embedded/encased. In addition, the piping/fitting and bolting shown in 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. For the aluminum bronze piping/fittings and bolting exposed to raw water—salt water (submerged) environment, the applicable aging effect is loss of material and the Periodic Surveillance and Preventive Maintenance Program is credited for managing this aging effect.

The applicant also stated that the ICW embedded/encased piping listed in LRA Table 3.3-9, page 3.3-63, is embedded/encased in concrete where it passes through the walls of the St. Lucie Units 1 and 2 CCW areas. The external environments are outdoor (Unit 1) and indoor not-air-conditioned (Unit 2) inside the CCW 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 Units 1 and 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. The applicant concluded, therefore, no aging effects requiring management are applicable to the embedded/encased ICW piping in this portion of the system.

On the basis of its review, the staff finds the applicant's response to RAI 3.3-3 concerning the components in emergency cooling canal system reasonable and adequate because the applicant identified the aging effect of loss of materials for the components in this system and credited the Periodic Surveillance and Preventive Maintenance Program for managing this aging effect. The staff also finds the applicant's response to the RAI concerning the ICW reasonable and adequate because plant-specific operating experience did not identify chloride-related corrosion as an aging effect for this piping system.

3.3.17.4 Chloride-Related Corrosion in Embedded/Encased Stainless Steel Piping/Fitting

In Table 3.3-11, "Primary Makeup Water," of the LRA, the applicant stated that no aging effect requiring aging management is applicable to stainless steel piping/fittings embedded/encased in concrete. Stainless steel components are much more resistant to chloride-related corrosion than carbon steel components. However, the applicant also stated that plant experience has identified loss of materials and cracking as applicable aging effects for stainless steel components in the ECCS pipe tunnel.

By letter dated July 1, 2002, the staff requested, in RAI 3.3-4, the applicant to explain why the aging effects applicable to stainless steel components in the ECCS pipe tunnel are not applicable to the stainless steel piping/fittings embedded/encased in concrete at St. Lucie. The applicant was also requested to discuss the operating history concerning stainless steel components in the embedded/encased environment to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that as indicated in the response to RAI 3.3.1-2, stainless steel components located in the ECCS tunnels at St. Lucie have greater susceptibility to corrosion (i.e., pitting and SCC) due to their potential for increased external chloride contamination. The applicant stated that the terms "tunnels" and "trenches" are synonymous at St. Lucie. This greater potential for external contamination applies to the components whose surfaces are exposed to the air environment in the tunnel, not to those which are embedded/encased in concrete. The high alkalinity of concrete provides an environment that protects the stainless steel from corrosion. The applicant also stated that its review of the St. Lucie plant-specific operating experience did not identify any intrusion of chlorides into concrete in a nonwetted (i.e., not submerged) environment resulting in degradation of embedded/encased stainless steel.

In addition, the applicant stated that primary water piping/fitting identified in LRA Table 3.3-11, page 3.3-68, as exposed to an external environment of embedded/encased, are associated with piping which penetrates concrete that is not wetted. Therefore, there is no potential for chloride intrusion into the concrete. As a result, the applicant concluded that loss of material and cracking are not aging effects requiring management for primary water components exposed to an embedded/encased environment.

On the basis of its review, the staff finds that the applicant's response is reasonable and adequate because the plant-specific operating experience did not identify any intrusion of chlorides into concrete in a nonwetted (i.e., not submerged) environment. In addition, there is a greater potential for external contamination to components whose surfaces are exposed to the air environment in the tunnel than there is to those components that are embedded/encased in concrete.

3.3.17.5 Corrosion Due to Carbonation in Embedded/Encased Carbon Steel Piping/Fitting

Even though the concrete structure in which the carbon steel components are embedded is only exposed to atmospheric air with negligible levels of chlorides, the embedded/encased steel piping/fittings may still be susceptible to a corrosion process attributable to the carbon dioxide present in the atmospheric air. This corrosion process operates via the generation of carbonic acid, which reduces the pH level in the vicinity of the steel/concrete interface. This neutralization process, in turn, disrupts the passivity of the protective films and permits attacks on the underlying carbon steel substrate. The water/cement ratio of the concrete is an important factor in affecting the rate of this corrosion process. By letter dated July 1, 2002, the staff requested, in RAI 3.3-5, the applicant to justify why this aging process is not applicable to St. Lucie, and to discuss the operating history to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that the corrosion process discussed in this RAI is carbonation. According to the Portland Cement Association, the depth of carbonation of good quality, well-cured concrete is generally of little significance. As discussed in LRA Sections 3.5.1.3 and 3.5.2.3, pages 3.5-9 and 3.5-24 respectively, St. Lucie structures are made from high quality concrete materials (high strength, high cement content, low water-cement ratio, and controlled curing). In addition, the operating experience at St. Lucie has not identified cracking or loss of material in steel piping/fitting embedded in concrete. Therefore, the applicant concluded that carbonation is not a mechanism that causes aging effects requiring management at St. Lucie.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because of the high quality concrete materials used by the applicant and the operating experience, which demonstrates that carbonation is not an aging mechanism that causes aging effects requiring management for embedded/encased carbon steel piping/fitting at St. Lucie.

3.3.17.6 Thermal Fatigue

In Section 3.3 of the LRA, the applicant did not identify cracking due to thermal fatigue as an aging effect requiring management for the auxiliary system components. Instead, the applicant identified thermal fatigue for piping systems designed to the requirements of ASME Section III, Class 2 and 3, and ANSI B31.1 as a TLAA in Section 4.3.3.2 of the LRA. The staff's evaluation of this TLAA is provided in Section 4.3 of this SER. Therefore, the aging effect due to thermal fatigue, as it applies to auxiliary system components, will not be discussed further in this section of the SER.

3.3.17.7 AMR for Additional Components Within Auxiliary Systems

The scoping requirements of 10 CFR 54.4(a)(2) include all non SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii). By letter dated July 1, 2002, the staff requested, in RAI 2.1-1, the applicant to provide additional information relating to its evaluation of non safety-related SSCs within the scope of license renewal.

In its response dated September 26, 2002, the applicant brought additional non safety-related SSCs into the scope of license renewal. The staff's evaluation of the applicant's scoping and screening methodology for identifying those piping systems and components is described in Section 2.1.3 of this SER, and will not be discussed further in this section of the SER. The staff's evaluation of these additional non safety-related components resulting from the applicant's scoping and screening process is discussed in Section 2.3.3 of this SER.

The applicant's response to the RAI also provides information regarding the management of aging effects associated with those additional non safety-related SSCs that are brought into the scope of license renewal. The staff's evaluation of the information pertaining to the management of aging effects associated with the components within the auxiliary systems follows.

Table 2.1-1 of the applicant's RAI response lists additional auxiliary systems components in the emergency diesel generator building, including piping/fittings and valves. Table 2.1-2 lists additional auxiliary systems components in the reactor auxiliary buildings, including piping/fittings, valves, and bolting (mechanical closures). The staff reviewed the information pertaining to component/commodity group, material, environment, aging effects requiring management, and program/activities. On the basis of its review, the staff finds that the aging effects identified for these additional components are consistent with those identified for other auxiliary systems components with the same combination of material and environment included in Section 3.3 of the LRA. In addition, the staff finds that the AMPs credited for managing these aging effects are the Chemistry Control Program and the Systems and Structures Monitoring Program. These two AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects as identified. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Therefore, the staff concludes that the applicant's response to RAI 2.1-1 is acceptable because the applicant has demonstrated that the aging effects associated with these additional non safety-related auxiliary systems components will be appropriately managed for the period of the extended operation.

By letter dated July 18, 2002, the staff requested, in RAIs 2.3.3-13, 2.3.3-15, and 2.3.3.15-1, the applicant justify why some SSCs listed in the UFSAR are not included within the scope of license renewal. In its responses, dated October 3 and November 27, 2002, the applicant brought additional components into the scope of license renewal for turbine cooling water system (Unit 1 only), fire protection system, and ventilation systems. Tables 3.3-14, 3.3-6, and 2.3.3-15-1-1 through -7 of the RAI response lists these additional components. The staff reviewed the information pertaining to component/commodity group, material, environment, aging effects requiring management, and program/activities. On the basis of its review, the staff finds that the aging effects identified for these additional components are consistent with those identified for other auxiliary systems' components with the same combination of material and environment included in Section 3.3 of the LRA.

In addition, the staff finds that the AMPs credited for managing these aging effects are Chemistry Control Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Fire Protection Program. To manage aging effect of loss of material in most of the ventilation system carbon steel components internally exposed to air/gas environment (atmospheric air or outside air with uncontrolled humidity and temperature), the applicant relies on the Periodic Surveillance and Preventive Maintenance Program. But in response to RAI 2.3.3.15-1, the applicant has committed to the use of the Systems and Structures Monitoring Program for managing loss of material in shield building ventilation system carbon steel damper housing, internally exposed to air/gas environment. However, the Systems and Structures Monitoring Program is typically utilized for managing external, and not internal, aging effects since it employs periodic visual inspections of external surfaces for evidence of degradation. The applicant provided the following justification for crediting the Systems and Structures Monitoring Program for managing loss of material at the inside surface of the shield building ventilation system damper housings. The ventilation dampers are located in indoor areas and their housings are internally coated, therefore, significant corrosion is not expected. 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. The applicant further stated that 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. The applicant also stated that 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. In addition, shield building ventilation is periodically tested to verify system capability. The staff finds this response acceptable because the visual inspections of the external surface of the damper housing performed as part of the Systems and Structures Monitoring Program would detect rust discoloration resulting from the significant corrosion on the inside surface while maintaining the intended function of the shield building ventilation system.

Furthermore, the Chemistry Control Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Fire Protection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects as identified. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Therefore, the staff concludes that the applicant's responses to RAIs 2.3.3-13, 2.3.3-15, and 2.3.3.15-1 are acceptable because the applicant has demonstrated that the aging effects associated with these additional auxiliary systems components will be appropriately managed for the period of the extended operation.

3.4 Steam and Power Conversion Systems

In Section 3.4, "Steam and Power Conversion Systems," of the LRA, the applicant describes the AMR for the SPCS. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the SPCS. The staff reviewed Section 3.4 and the applicable portions of Appendices A, B, and C to determine whether the applicant provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3) for the SPCS' structures and components that are determined to be within the scope of license renewal and subject to an AMR.

The SPCS include the following systems.

- main steam, auxiliary steam, and turbine system
- main feedwater and SG blowdown system
- auxiliary feedwater and condensate system

In Section 2.3.4 of the LRA, the applicant provides a description of these systems and identifies the components requiring an AMR for license renewal. The staff's evaluation of the scoping methodology and the SPCS' structures and components included within the scope of license renewal and subject to an AMR is documented in Sections 2.1 and 2.3.4, respectively, of this SER. In LRA, Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). In LRA, Appendix B, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In LRA, Appendix C, the applicant describes the process used to identify many of the applicable aging effects for the SCs that are subject to an AMR. In LRA, Appendix D, the applicant states that no changes to the St. Lucie, Units 1 and 2, Technical Specifications have been identified.

3.4.0 Condensate Storage Tank Cross-Connect Buried Piping Inspection (Unit 1 only)

The Condensate Storage Tank Cross-Connect Buried Piping Inspection (Unit 1 only) AMP is specific to the SPCS. The staff's evaluation of this AMP is provided below.

The Condensate Storage Tank Cross-Connect Buried Piping Inspection Program is described in Section 3.1.1 of Appendix B to the LRA. The applicant credits this program for managing the external loss of material due to pitting and microbiologically influenced corrosion of components in the Unit 1 auxiliary feedwater and condensate system. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.0.1 Summary of Technical Information in the Application

The applicant credits the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program for aging management of the external surface of buried piping that cross-connects the condensate storage tanks (CST). This one-time inspection is plant specific. The GALL Report includes a similar program, Program XI.M28, "Buried Piping and Tanks Surveillance;" however, XI.M28 cannot be used for St. Lucie because XI.M28 is intended for carbon steel piping, whereas the St. Lucie CST cross-connect pipe is stainless steel.

3.4.0.2 Staff Evaluation

The staff's evaluation of the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program focused on how the applicant demonstrates that the applicable aging effects of the SCs that credit this program will be managed for the period of extended operation. The staff evaluated the program against the following 10 elements that are described in Appendix A to NUREG 1800—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the program provides for inspection of a selected portion of the buried CST cross-connect pipe. The scope is acceptable to the staff because it includes those components that rely on the program for aging management.

Preventive Actions: The applicant stated that no preventive actions are applicable to this inspection, and the staff concurs with this position.

Parameters Monitored or Inspected: The applicant stated that the inspection will assess the extent of external corrosion of the CST cross-connect piping based on surface conditions at a selected location. The location for inspection will be selected based on the worst-case condition for moisture. The examination will be performed to identify the potential effects of external loss of material due to pitting and MIC. This is in accordance with general industry practice, and is acceptable to the staff.

Detection of Aging Effects: The applicant stated that the inspection provides for visual examination of the external surfaces of buried CST cross-connect pipe to detect loss of material. The applicant also stated that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will use techniques with demonstrated capability and a proven industry record to assess external surface conditions of the buried portions of stainless steel. The examination will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been previously used to assess piping condition in many other plant systems. Because there is no operating history of degradation, a one-time inspection was selected. This is acceptable to the staff, since the degree of reduction of wall thickness due to pitting and MIC, as a result of loss of external surface material, is readily determinable by visual inspection.

Monitoring and Trending: The applicant stated that the one-time inspection will provide confirmatory information on the condition of the pipe. Visual inspection will detect degradation of the external surface of the pipe, and lead to thickness measurement if necessary. Because there is no operating history of degradation, a one-time inspection was selected. If significant loss of material is detected, the appropriate corrective action, including program revision if needed, will be implemented. This is acceptable, since piping thickness measurements will permit calculation of an outside diameter corrosion rate.

Acceptance Criteria: The applicant stated that the results of the examinations will be evaluated in accordance with the minimum wall thickness requirements of the applicable design code (ANSI B31.1). This will ensure that the integrity of the pipe is maintained, and is, therefore, acceptable.

Operating Experience: This is a one-time inspection, so there is no operating experience associated with this program. The applicant stated that there is no operating experience of degradation of this piping. The staff finds this reasonable and acceptable.

3.4.0.3 UFSAR Supplement

The staff reviewed summary description of the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program in the UFSAR supplements in Appendix A to the LRA. The staff finds that the information provided in the UFSAR supplements for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.4.0.4 Conclusions

The staff has reviewed the information provided in Section 3.1.1 of Appendix B of the LRA, and the summary description of the Condensate Storage Tank Cross-Connect Buried Piping Inspection program in Appendix A of the LRA. On the basis of this review and the above evaluation, the staff finds that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.1 Summary of Technical Information in the Application

In Section 3.4 of the LRA, the applicant identifies three systems that require an AMR, in accordance with 10 CFR 54.21(a)(3). The three systems are main steam, auxiliary steam, and turbine; main feedwater and SG blowdown; and auxiliary feedwater and condensate. In Section 2.3.4 of the LRA, the applicant describes these systems.

Main steam, auxiliary steam, and turbine components subject to an AMR include valves (pressure boundary only), steam traps, strainers, thermowells, orifices, piping, tubing, and fittings. The intended functions for main steam, auxiliary steam, and turbine components subject to an AMR are pressure boundary integrity, filtration, and throttling. A complete listing of these components that require an AMR and the component intended functions are provided in Table 3.4-1 of the LRA.

Main feedwater and SG blowdown components subject to an AMR include valves (pressure boundary only), accumulators, orifices, thermowells, piping, tubing, and fittings. The intended functions for the main feedwater and SG blowdown components subject to an AMR are pressure boundary integrity and throttling. A complete list of main feedwater and SG blowdown components that require an AMR and the component intended functions are shown in Table 3.4-2 of the LRA.

Auxiliary feedwater and condensate components subject to an AMR include tanks, pumps, turbines, and valves (pressure boundary only), coolers, orifices, vortex breakers, sight glasses, piping, tubing, and fittings. The intended functions for auxiliary feedwater and condensate components subject to an AMR are pressure boundary integrity, heat transfer, vortex prevention, and throttling. A complete list of auxiliary feedwater and condensate components that require an AMR and the component intended functions are provided in Table 3.4-3 of the LRA.

3.4.1.1 Aging Effects

In Table 3.4-1 through 3.4-3 of the LRA, the applicant describes the aging effects requiring management, and the programs and activities that manage the aging effects for each applicable environment and material combination. In Section 3.4 of the LRA, the applicant summarizes the following aging effects requiring management for each system.

Main Steam, Auxiliary Steam, and Turbines: The aging effects requiring management are loss of material for carbon steel, stainless steel, and nickel alloy components, and cracking for certain stainless steel and nickel alloy components. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue of main steam piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a TLAA and is addressed in Section 4.3.2 of the LRA.

Main Feedwater and Steam Generator Blowdown: The aging effects requiring management are loss of material for carbon steel and stainless steel components, and cracking for certain stainless steel components. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue of main feedwater piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a TLAA and is addressed in Section 4.3.2 of the LRA.

Auxiliary Feedwater and Condensate: The aging effects requiring management are loss of material for carbon steel and stainless steel components. Fatigue of auxiliary feedwater piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a TLAA and is addressed in Section 4.3.2 of the LRA.

3.4.1.2 Aging Management Programs

In Section 3.4 of the LRA, the applicant identifies the following eight AMPs that are utilized to manage the aging effects associated with the SCs of the SPCS.

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Condensate Storage Tank Cross-Connect Buried Pipe Inspection Program
- Pipe Wall Thinning Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the SCs of the SPCS will be adequately managed by these AMPs for the period of extended operations.

3.4.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Scoping and Screening Results," of this LRA, and the applicable AMP descriptions provided in Appendix B of the LRA, to determine whether the aging effects for the SPCS components have been properly identified and will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects, and the applicant's programs credited for the aging management of the SPCS components at St. Lucie. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the SPCS components.

3.4.2.1 Aging Effects

Tables 3.4-1, 3.4-2, and 3.4-3 of the LRA identify the following applicable aging effects.

- loss of material of carbon steel in treated water, borated water, lubricating oil, outdoor air, and containment air environments

- loss of material and/or cracking of stainless steel in treated water, lubricating oil and buried environments

- loss material and/or cracking of nickel alloy in treated water environment

- loss of mechanical closure integrity of carbon steel in borated water environment

The only parts of systems or components considered to be inaccessible for inspection are those that are buried or embedded/encased in concrete. These environments are addressed as part of the AMR process and are identified in Table 3.0-2, "External Service Environments," of the LRA. Potential aging effects associated with these environments are reviewed, and those aging effects requiring management are identified along with the credited AMPs. The only portion of the SPCS containing inaccessible piping is auxiliary feedwater, which contains sections of buried and embedded stainless steel piping.

In RAI 3.4-1, the staff requested that the applicant explain why moisture and liquid pooling effects in an internal air/gas environment were not considered as an aging effect for stainless steel components. In its response dated September 26, 2002, the applicant stated the following.

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

This position is consistent with that accepted by the NRC previously for similar LRA reviews. The staff finds the applicant's response reasonable and acceptable. On this basis, the RAI 3.4-1 concerns are considered resolved.

In RAI 3.4-2, the staff requested that the applicant explain why the effects of humidity in an external environment are not considered to cause aging that leads to a loss of preload for carbon steel bolts. In its response dated September 26, 2002, the applicant stated the following.

> Although the LRA identifies bolting (mechanical closures) material as carbon steel, the actual bolting standard for St. Lucie Units 1 and 2 piping components is low alloy steel ASTM A193, Grade B7. This material provides increased corrosion resistance over plain carbon steel. The bolting associated with Main Steam, Auxiliary Steam, Turbine, Main Feedwater and SG Blowdown is typically in a dry environment, coated with a lubricant, and exposed to temperatures greater than 212 °F. Therefore, moisture is not present on the surfaces of piping or associated bolting, and as a result loss of material due to general corrosion does not require management.
>
> Review of the St. Lucie plant experience, which was performed as part of the aging management review (AMR) process, confirmed that no loss of mechanical closure integrity has occurred due to general corrosion of bolting. Review of industry experience also confirms that general corrosion of bolting has not been a major concern and therefore is not an aging effect requiring management.
>
> Aging effects associated with bolting are described in the LRA, Appendix C, Section 5.4, Loss of Mechanical Closure Integrity. The only aging effect determined to require management associated with bolting is loss of mechanical closure integrity due to boric acid corrosion for components in proximity to borated water systems.

This position is consistent with that previously accepted by the NRC as part of similar LRA reviews. The staff finds the applicant's response reasonable and acceptable. Based on the above discussion, the RAI issue is considered resolved.

In RAI 3.4-3, the staff requested that the applicant justify the exclusion of FAC as an aging mechanism that can cause wall thinning in auxiliary feedwater piping components. The scope of the Flow-Accelerated Corrosion Program includes main feedwater, blowdown, and main steam and turbine, but not auxiliary feedwater piping and components.

In its response dated September 26, 2002, the applicant stated the following.

> The St. Lucie Flow Accelerated Corrosion Program is based on industry consensus standard, NSAC-202L-R2, Recommendations for an Effective Flow Accelerated Corrosion Program. This document states in Section 4.2.2 that:
>
> Some susceptible systems, or portions of systems, can be excluded from further evaluation due to their relatively low level of susceptibility. Based on both laboratory and plant experience, the following systems can be safely excluded from further evaluation:
>
> Systems with no flow, or those that operate less than 2 percent of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F less than 2 percent of the plant operating time.

The applicant also confirmed that the auxiliary feedwater at St. Lucie is operated for less than 2 percent of the plant operating time. As a result, loss of material due to flow accelerated corrosion is not an aging effect requiring management for auxiliary feedwater.

The staff finds that the applicant's response satisfactorily addresses the staff's concern because it is consistent with industry consensus standards and the staff position. On this basis, the RAI issue is considered to be resolved.

In RAI 3.4-4, the staff requested that the applicant explain how the Boric Acid Wastage Surveillance Program manages the aging effects associated with elevated temperatures and stress levels to prevent loss of preload in mechanical bolting. In its response dated September 26, 2002, the applicant stated the following.

> The Boric Acid Wastage Surveillance Program is not credited for managing aging effects associated with elevated temperatures and stress levels to prevent loss of pre-load in mechanical joints.
>
> As discussed in LRA Appendix C, Subsection 5.4, "Loss of Mechanical Closure Integrity," the effect of loss of pre-load resulting from temperature effects and cyclic loading is external leakage of the internal fluid at a mechanical joint. With the exception of borated water leaks, there are no aging effects requiring management associated with external leakage of a mechanical joint. Loss of mechanical closure integrity resulting from borated water leaks is addressed in the LRA as discussed below.
>
> When external leakage involves borated water, the aging effect of concern is loss of material due to aggressive chemical attack (i.e., boric acid corrosion of carbon or low-alloy steel bolting). Therefore, the LRA addresses loss of mechanical closure Integrity resulting from the external environment of "borated water leaks" and credits the Boric Acid Wastage Surveillance Program for management of this aging effect.

This position is consistent with that previously accepted by the NRC as part of similar LRA reviews. The staff finds that the applicant's response satisfactorily addresses the staff's concern and the RAI issue is considered resolved.

The applicant provided references to St. Lucie plant-specific as well as industry-wide experience to support its identification of applicable aging effects for SPCS. The staff concludes that, on the basis of the description of the internal and external environments and material of fabrication for these systems, the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.4.2.2 Aging Management Programs

In Section 3.4 of the LRA, the applicant identifies the following eight AMPs that are utilized to manage the aging effects associated with the SC of the steam and power conversion systems.

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Condensate Storage Tank Cross-Connect Buried Pipe Inspection Program
- Pipe Wall Thinning Program

The staff evaluated the eight AMPs associated with the SPCS to determine if they contain the essential elements needed to provide adequate aging management of the components in the SPCS so that there is reasonable assurance that the components will perform their intended functions in accordance with the CLB for the period of extended operation. Seven of the AMPs are common to several systems and are evaluated in Section 3.0.5 of this SER. The Condensate Storage Tank Cross-connect Buried Piping Inspection Program (Unit 1 only) is a system-specific AMP and is evaluated in Section 3.4.0.1 of this SER.

On the basis of the information provided, the staff finds that the above-listed eight AMPs are appropriate and acceptable for managing the aging effects associated with the components.

3.4.3 Conclusions

The staff has reviewed the information in LRA Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4 "Steam and Power Conversion Systems," as well as the applicant's responses to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that aging effects associated with the SPCS will be adequately managed so that there is a reasonable assurance that the intended functions of these systems will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the SPCS as required by 10 CFR 54.21(d).

3.5 Aging Management of Structures and Structural Components

In Section 3.5, "Structures and Structural Components," of the LRA, the applicant describes the AMR for structures and associated components. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the SC. The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effect of aging on the following structures and structural components will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

- containments
- component cooling water areas
- condensate polisher building
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fire rated assemblies
- fuel handling buildings
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

In Section 2.4 of the LRA, the applicant provides a description of these structures and identifies the SCs requiring an AMR for license renewal. In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d).

3.5.0 Aging Management Programs

3.5.0.1 ASME Section XI, Subsection IWE Inservice Inspection Program

The ASME Section XI, Subsection IWE Inservice Inspection Program is described in Section 3.2.2.2 of Appendix B to the LRA. This program provides aging management of the containment buildings for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the ASME Section XI, Subsection IWE Inservice Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.1.1 Summary of Technical Information in the Application

Chapter 3 of the LRA identifies the specific structural component/commodity groups that credit the ASME Section XI, Subsection IWE Inservice Inspection Program for aging management. Instead of describing the 10 elements relevant to the program, the LRA states that the ASME Section XI, Subsection IWE Inservice Inspection Program is consistent with the 10 attributes of AMPs XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," specified in the GALL Report. Moreover, the LRA explains that for St. Lucie Units 1 and 2, leak rate testing in accordance with 10 CFR Part 50, Appendix J, is included as Category E-P in the ASME Section XI, Subsection IWE Inservice Inspection Program. The currently applicable ASME code for the ASME Section XI, Subsection IWE Inservice Inspection Program is identified in FPL Letters L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7 of the LRA], and L-2000-227, dated November 13, 2000, for Unit 2 [Reference B-10 of the LRA].

The LRA also provides the operating experience based on the inspection of the containments. The operating experience is summarized as follows.

- Degraded coatings without corrosion were observed on several Unit 1 electrical penetrations.

- Missing coatings were identified on the Unit 1 containment dome.

- Pitting was observed on the Unit 2 containment vessel exterior in the vicinity of the annulus floor. The maximum depth was analyzed and determined to be acceptable. The affected area was coated and follow-up inspections were performed.

- The Unit 2 containment personnel airlock outer door handwheel shaft seal failed during the semi-annual strongback test. The cause was determined to be misalignment, and therefore, not age related.

- Cracking of the moisture barrier between the steel containment vessel and the concrete floor was observed on Unit 2. Sealant material was removed and the containment vessel was inspected. Minor corrosion was observed, but no vessel repairs were required.

- Degraded coatings and minor corrosion were observed at a piping penetration on Unit 2. The area was cleaned and recoated in accordance with plant procedures.

Based upon the above, the applicant concluded that the continued implementation of the ASME Section XI, Subsection IWE Inservice Inspection Program will ensure that the intended functions of the systems and components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.1.2 Staff Evaluation

The staff verified that the components, as identified in Table 3.5-2 of the LRA, to which the ASME Section XI, Subsection IWE Inservice Inspection Program applies, are commensurate with the intent of the GALL Report, Programs XI.S1 and XI.S4. The staff finds the process acceptable. The staff considers the XI.S1 a containment condition monitoring program, and XI.S4 a containment leakage monitoring program. Both programs are needed to ensure the intended functions (functions 1, 2, 7, and 10 of Table 3.5-1 of the LRA) of the containments. The applicant will implement GALL Program XI.S4 in accordance with the requirements of the plant technical specifications. The staff finds this acceptable.

Table 3.5-2 of the LRA indicates that the aging management of the containment bellows is included within the ASME Section XI, Subsection IWE Inservice Inspection Program. Recognizing the susceptibility of the bellows to cracking due to transgranular stress corrosion cracking (see NRC Information Notice 92-20), the staff asked the applicant to provide the operating experience related to the condition of bellows at St. Lucie Units 1 and 2 and the method used to detect degradation of the inaccessible bellows (RAI B.3.2.2-1).

By letter dated September 26, 2002, the applicant provided the following response.

> NRC Information Notice 92-20 "Inadequate Local Leak Rate Testing" addresses circumstances involving local leak rate testing and an instance where the cause of measured leakage was due to bellows cracking apparently for an in-line bellows (i.e., bellows that are an integral part of the process piping system). The events described by the information notice occurred while testing bellows configurations routinely utilized in boiling water reactor type power plants, and the root

cause of the identified cracking is not addressed in the notice.

> The containment vessel piping penetration bellows that are installed at St. Lucie Units 1 and 2 are predominantly structural type bellows, designed such that the bellows are not subjected to piping operating system parameters (i.e., not part of the process line pressure boundary). Aging management review results (LRA Table 3.5-2, page 3.5-37) concluded that the stainless steel (expansion joint) portions of the penetration bellows exposed to containment air or indoor-not-air-conditioned environments do not experience aging effects requiring management.
>
> St. Lucie plant-specific operating experience has not identified cracking of these bellows as an aging effect requiring management. Bellows that form a portion of the containment leak tight boundary are leak rate tested in accordance with ASME Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2, page B-26 - Appendix J leak rate testing).

Considering the operating experience stated in the response, the staff considers that the two-ply bellows at St. Lucie are testable under Type B testing of the containment penetrations, and that the integrity of the bellows will be maintained through the Appendix J testing during the period of license renewal. Therefore, the staff finds this acceptable.

The staff also requested clarification of the testing of containment isolation valves (RAI B.3.2.2-2), since GALL Program XI.S4 provides an option for leakage testing of containment isolation valves either (1) under Type C test, or (2) along with the tests of the systems containing the containment isolation valves. By letter dated September 26, 2002, the applicant provided the following response.

> Currently, all St. Lucie plant containment isolation valves that require testing under 10 CFR 50, Appendix J, are tested per Appendix J, Option B, Type C test, as part of the AMSE (sic. ASME) Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2 page B-26). Currently there are no plans to change these test methods during the extended period of operation.

The staff considers the option chosen by the applicant acceptable, as it will comply with the requirements of Option B of Appendix J, as approved by the staff in the plant technical specifications.

The staff also requested information related to the applicant's operating experience with the containment leak rate testing (RAI B.3.2.2-3). In response, by letter dated September 26, 2002, the applicant listed the reports it had submitted to NRC after each containment leak rate testing since operation of each unit. The staff reviewed the reports and discovered that the procedures used to conduct Type A, Type B, and Type C testing have been modified and improved with time based on the industry experience reflected in various revisions of ANSI/ANS-56.8, "Containment System Leakage Testing Requirements." The staff concludes that continued use of the procedures to conduct the tests and report the test results for the extended period of operation will ensure that the containment leak tight integrity will be verified, and the staff finds this acceptable.

The applicant stated that the ASME Section XI, Subsection IWE Inservice Inspection Program is consistent with the 10 attributes of AMPs XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," specified in the GALL Report. The staff has reviewed the information provided in Section 3.2.2.2 of the LRA, the summary description of the ASME Section XI, Subsection IWE Inservice Inspection Program in Appendix A of the LRA, the description of the Appendix J testing in the plant technical specifications, and the applicant's September 26, 2002, response to the staff's RAIs.

The staff verified that the components, as identified in Table 3.5-2 of the LRA, to which the ASME Section XI, Subsection IWE Inservice Inspection Program applies are consistent with the GALL Report, Programs XI.S1 and XI.S4. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff generated Open Item 3.0.2.2-1 to track this issue. The inspection findings confirmed that there were no open items related to license renewal and verified the applicant's claim that specific AMP are consistent with the GALL Report. Therefore, the staff considers Open Item 3.0.2.2-1 to be closed.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMPs XI.S1 and XI.S4 in the UFSAR supplements' descriptions of this AMP. This was tracked as Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP XI.S1 and XI.S4. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.5.0.1.3 UFSAR Supplement

The staff reviewed Section 18.2.2.2 of the UFSAR supplement summary description of the ASME Section XI, Subsection IWE Inservice Inspection Program in Appendix A of the LRA, and the Appendix J leak rate testing program for containment leak rate testing described in the plant technical specifications. The staff finds that the information given in the UFSAR supplement provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.5.0.1.4 Conclusions

The staff concludes that the ASME Section XI, Subsection IWE Inservice Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.2 ASME Section XI, Subsection IWF Inservice Inspection Program

The ASME Section XI, Subsection IWF Inservice Inspection Program is described in Section 3.2.2.3, of Appendix B to the LRA. This program provides for condition monitoring of component supports in several structures that are within the scope of license renewal. The staff reviewed the ASME Section XI, Subsection IWF Inservice Inspection Program to determine whether the applicant has demonstrated that this program will adequately manage the aging effects for the component supports that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.2.1 Summary of Technical Information in the Application

Section 3.2.2.3 of Appendix B to the LRA states that the ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with GALL Program XI.S3, "ASME Section XI, Subsection IWF." The LRA states that the program is credited for aging management of Class 1, 2, and 3 component supports in the following structures.

- component cooling water areas
- condensate storage tank enclosures

- containments
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fuel handling buildings
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- ultimate heat sink dam
- yard structures

The LRA also describes the operating experience with the ASME Section XI, Subsection IWF Inservice Inspection Program. The program is a condition monitoring program that provides for the implementation of ASME Code, Section XI, in accordance with the provisions of 10 CFR 50.55a. The 10-year examination plan provides a systematic guide for performing nondestructive examination of passive components in the scope of license renewal. Based on this, the applicant concluded that the ASME Section XI, Subsection IWF Inservice Inspection Program will adequately manage the aging effects so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.2.2 Staff Evaluation

The applicant stated that the ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with the 10 attributes of AMP XI.S3, "ASME Section XI, Subsection IWF," specified in the GALL Report. The staff verified that the components, as identified in Section 3 of the LRA, to which the ASME Section XI, Subsection IWF Inservice Inspection program applies are commensurate with the intent of the GALL Report AMP. The staff review noted that, as indicated in Table 3.5-2 of the LRA, the containments contain safety-related piping and component supports, RV supports, pressurizer supports, RCP supports, and SG supports, all manufactured from carbon steel, which are exposed to the containment air environment. The applicant credited the Subsection IWF Inservice Inspection Program for managing the aging effects (loss of material) for these piping and component supports. Tables 3.5-3, 3.5-5, 3.5-6, 3.5-7, 3.5-9, 3.5-11, and 3.5-12 of the LRA indicated, respectively, the component cooling water areas, CST enclosures, diesel oil equipment enclosures, emergency diesel generator buildings, fuel handling buildings, intake structures, and RABs, which contain safety-related piping and component supports, manufactured from carbon steel, and are exposed to an indoor not-air-conditioned or outdoor environment. Based on Tables 3.5-13, 3.5-15, and 3.5-16, the steam trestle areas, ultimate heat sink dam, and yard structures, respectively, also contain safety-related piping and component supports, manufactured from carbon steel, which are exposed to the outdoor environment. The applicant credited the Subsection IWF Inservice Inspection Program for managing the aging effect (loss of material) for these piping and component supports. The staff finds this acceptable because the components that credit this program are commensurate with the intent of the GALL Report AMP.

The applicant further stated that the Subsection IWF Inservice Inspection of the Class 1, 2, and 3 component supports has been conducted on both units since plant initial startup. The visual examinations of Class 1, 2, and 3 component supports look for deformations or structural degradations, corrosion, and other conditions that could affect the intended function of the support. Conditions noted during the inspection of component supports are documented on inspection reports. Loss of material has been identified for numerous supports. Evaluations have determined the loss of material was caused by general corrosion. The degraded supports were entered into the corrective action program, and repaired or replaced as appropriate. The staff finds that the past plant operation serves to demonstrate successful future performance of the ASME Section XI, Subsection IWF Inservice Inspection Program.

The staff inspected the ASME Section XI, Subsection IWF Inservice Inspection Program for acceptability and compared the programs 10 elements to the 10 elements discussed in GALL AMP XI.S3. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff generated Open Item 3.0.2.2-1 to track this issue. The inspection findings confirmed that there were no open items related to license renewal and verified the applicant's claim that specific AMP are consistent with the GALL Report. Therefore, the staff considers Open Item 3.0.2.2-1 to be closed.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.S3 in the UFSAR supplements' descriptions of this AMP. This was tracked as Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP XI.S3. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

3.5.0.2.3 UFSAR Supplement

The staff reviewed the summary description of the ASME Section XI, Subsection IWF Inservice Inspection Program in Section 18.2.2.3 of the UFSAR supplement in Appendix A to the LRA. The staff finds that the information provided in the UFSAR supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.5.0.2.4 Conclusions

The staff concludes that the continued implementation of the ASME Section XI, Subsection IWF Inservice Inspection Program will provide reasonable assurance that the aging effects for the Class 1, 2, and 3 piping and component supports within the scope of license renewal will be adequately managed such that the intended functions of the piping and component supports will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.3 Boraflex Surveillance Program

3.5.0.3.1 Summary of Technical Information in the Application

The applicant described its boraflex surveillance program in Section 3.2.3, "Boraflex Surveillance Program (Unit 1 only)," of Appendix B to the LRA. The staff reviewed the application to determine whether the applicant had demonstrated that the Boraflex Surveillance Program will adequately manage the applicable aging effects in the plant for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The Boraflex Surveillance Program, applicable only to Unit 1, is credited for managing the aging of spent fuel pool (SFP) storage rack panels for the period of extended operation. The Boraflex

Surveillance Program is a performance monitoring program that manages the degradation of the panels in the spent fuel storage racks due to gamma irradiation. The Boraflex panels ensure that the reactivity of the storage fuel assemblies is maintained within required limits.

The applicant states that the Boraflex Surveillance Program is consistent with the 10 program elements of AMP XI.M22, "Boraflex Monitoring," as specified in NUREG-1801, Volume 2, "Generic Aging Lessons Learned (GALL) Report", dated April 2001. The applicant also states that commitment dates associated with implementation of this AMP are contained in Appendix A to the LRA. The current program includes blackness testing to monitor parameters including physical conditions of the boraflex panels in terms of gap information, gap distribution, and gap size. Trending of the SFP silica concentration is conducted to give a qualitative indication of boron carbide loss from the panels. In addition, the applicant states that, during the period of extended operation, the Boraflex Surveillance Program will be enhanced to include areal density testing. Commitment dates associated with the enhancement to this program are contained in Appendix A to the LRA.

3.5.0.3.2 Staff Evaluation

The 10 program elements in the GALL Report, AMP XI.M22, "Boraflex Monitoring," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage the degradation of the panels in the spent fuel storage racks due to gamma irradiation. In Appendix B, Section 3.2.3, to the LRA, the applicant has stated that the program elements for the Boraflex Surveillance Program are consistent with those specified in Program XI.M22 of the GALL Report. The applicant retains the program description of the Boraflex Surveillance Program, as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station. In addition, the program will be enhanced to include areal density testing. The testing will measure the Boron-10 areal density to ascertain the depletion of boron carbide from boraflex panels.

The staff inspected the Boraflex Surveillance Program for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M22. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. On the basis of these considerations, the staff concludes that the Boraflex Surveillance Program provides an acceptable means of managing the potential degradation of the panels in the spent fuel storage racks. The staff generated Open Item 3.0.2.2-1 to track this issue. The inspection findings confirmed that there were no open items related to license renewal and verified the applicant's claim that specific AMP are consistent with the GALL Report. Therefore, the staff considers Open Item 3.0.2.2-1 to be closed.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M22 in the UFSAR supplement's descriptions of this AMP. This was tracked as Confirmatory Item 3.0.2.2-1. In its March 28, 2003, response to Confirmatory Item 3.0.2.2-1, the applicant indicated that it will modify the Units 1 and 2 UFSAR supplement descriptions to include references to GALL AMP XI.M22. Therefore, the staff considers Confirmatory Item 3.0.2.2-1 to be closed.

The staff has reviewed the Boraflex Surveillance Program in Section 3.2.3 of Appendix B of the LRA, and the UFSAR supplement summary description of the Boraflex Surveillance Program in Section 18.2.3 of Appendices A1 and A2 of the LRA. On the basis of this review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with the structures and components of the Boraflex Surveillance Program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.3.3 UFSAR Supplement

Section 18.2.3, of Appendix A1 to the LRA, provides the applicant's UFSAR supplement for the Boraflex Surveillance Program at St. Lucie. The staff reviewed the section to verify that the information in the UFSAR supplement provides an adequate summary of the program activities required by 10 CFR 54.21(d). The staff finds the UFSAR supplement sufficient.

3.5.0.3.4 Conclusions

The staff concludes that the Boraflex Surveillance Program will provide reasonable assurance that the effects of aging associated with the SCs within the scope of license renewal will be adequately managed such that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.1 Containments

3.5.1.1 Summary of Technical Information in the Application

The AMR results for the containment, which consists of the freestanding steel containment vessel surrounded by the reactor containment shield building, are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA identifies the components of the containment structures along with their (1) intended functions, (2) material, (3) environment, (4) aging effects, and (5) AMPs.

Section 2.4.1 of the LRA states that each St. Lucie containment consists of the freestanding steel containment vessel surrounded by the reactor containment shield building. Each containment houses the RCSs and the RCS. Additionally, each containment houses and supports components required for plant refueling, including the polar crane, refueling cavity, and portions of the fuel handling system.

The materials of construction for the containment structure, as shown in Table 3.5-2 of the LRA, are steel, concrete, and miscellaneous materials such as silicone, elastomers, and lubrite plates.

The containment structure components are exposed to containment air, indoor not-air-conditioned and outdoor, borated water leaks, treated water, and a buried environment.

3.5.1.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in the containment structure.

- loss of material of carbon steel in containment air, indoor not-air-conditioned, outdoor, or exposed to borated water leaks

- loss of material of galvanized carbon steel exposed to borated water leaks

- loss of material of stainless steel in treated water - borated

- loss of material of concrete in an outdoor environment

- loss of material and change in material properties for concrete in a buried environment

- loss of seal for elastomers exposed to containment air, indoor-not-air-conditioned, outdoor, or treated water - borated

3.5.1.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in the containment structure.

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the containment structure will be adequately managed by these AMPs such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.1.2 Staff Evaluation

In addition to Section 3.5.1 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results—Structures," and the applicable AMP descriptions provided in Appendix B to the LRA, to determine whether the aging effects for the containment components have been properly identified and will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the applicant's programs credited for the aging management of the containment structural components at St. Lucie. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the containment components.

3.5.1.2.1 Aging Effects

<u>Concrete</u>. The applicant identifies loss of material and change in material properties as applicable aging effects for below-grade reinforced concrete structural components. However, for reinforced concrete in accessible portions of the containment structures, such as exterior walls and roofs, the applicant does not identify any applicable aging effects. In addition, the applicant does not identify any applicable aging effects for reinforced concrete located within the containment (interior shield walls, beams, slabs, missile shields, equipment pads) or for

reinforced masonry block walls.

The staff considers cracking, change in material properties, and loss of material to be applicable aging effects for concrete containment components that are exposed to either sheltered interior or outdoor environments. The NRC staff position regarding the aging management of in-scope concrete SCs is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation depending on the stresses and strains due to normal and incidental loadings, as well as the environment to which they are subjected. Concrete SCs subjected to sustained loading—such as crane or monorail operation—and/or sustained adverse environmental conditions—such as high temperatures, humidity, or chlorides—will degrade, thereby potentially affecting the intended function(s) of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects are accentuated. On the basis of industry-wide evidence, the ACI has published a number of documents (e.g., ACI 201.2R-77, "Guide for Making a Condition Survey of Concrete," ACI 224.1R, "Causes, Evaluation and Repairs of Cracks in Concrete Structures," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures") that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent characteristics of concrete structures to degrade, with time, if not properly managed. Similar observations of concrete aging, made by NRC staff, are detailed in NUREG-1522, "Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures." As such, in RAI 3.5-1, the staff requested that the applicant identify AMPs that will be used to manage the aging effects for the concrete containment components listed in Table 3.5-2 of the LRA.

By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant stated the following.

> The analysis of possible aging effects for reinforced concrete components in the Containments and Other structures are summarized in the LRA Subsections 3.5.1.3 and 3.5.2.3 (page 3.5-9 and 3.5-24, respectively). The analysis is based on concrete material properties, the applicable environments, and years of operating experience. The analysis concludes that concrete structures exposed to aggressive environments require aging management, and concrete structures not exposed to aggressive environments do not require aging management.
>
> However, based on specific direction from NRC staff, license renewal applicants are required to implement an aging management program to manage aging of concrete structures. FPL proposes to credit the Systems and Structures Monitoring Program (LRA Appendix B Subsection 3.2.14 page B-57) for managing aging (including cracking, loss of material, and change in material properties) of the accessible reinforced concrete structures listed in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93).

The applicant's commitment to monitor concrete aging effects in accessible areas is acceptable to the staff. The applicant has decided to use the Systems and Structures Monitoring Program to manage concrete aging, which is reviewed in Section 3.0.5.10 of this SER. The staff considers the applicant's response to RAI 3.5-1 to be adequate with respect to managing the aging of concrete structural components for the period of extended operation.

For unreinforced concrete masonry block walls, the applicant has committed to manage cracking for the period of extended operation. However, for reinforced concrete masonry block walls, the applicant did not identify any applicable aging effects. Reinforced concrete masonry block walls are found in the containment structure (LRA Table 3.5-2). In RAI 3.5-12, the staff requested that the applicant justify this conclusion. In response, the applicant stated the following.

> Cracking of reinforced masonry block walls is not an aging effect requiring management since the reinforcing steel effectively controls cracking thus preventing a loss of intended function. During IE Bulletin 80-11, "Masonry Wall Design," walkdowns, no significant cracking was identified. Furthermore, after many years of service, reinforced masonry block walls at St. Lucie have not exhibited cracking that could lead to a loss of intended function. For that reason, cracking of reinforced masonry block walls is not an aging effect requiring management. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

The applicant's decision to not manage the aging of reinforced concrete masonry walls is not acceptable to the staff. The staff does not distinguish between the AMRs for general reinforced concrete components, which are discussed above and in RAI 3.5-1, and those for reinforced concrete masonry block walls. In a letter dated December 23, 2002, the applicant modified its response to RAI 3.5-12 by stating that the Systems and Structures monitoring program will be used to manage cracking for reinforced concrete masonry block walls listed in LRA Table 3.5-2. The applicant's decision to manage cracking for reinforced concrete masonry walls is acceptable to the staff. Therefore, RAI 3.5-12 is considered to be resolved.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/ground water environment is nonaggressive. The applicant, however, acknowledges that the soil/ground water environment at St. Lucie is potentially aggressive. In RAI 3.5-9, the staff requested that the applicant describe the condition of below-grade concrete structural components and provide the average levels of contaminants (chlorides and sulfates) and pH level in the ground water at the St. Lucie site. By letter dated September 26, 2002, the applicant stated that the intake structures have experienced concrete degradation that warranted corrective actions and that other concrete structures located below ground water have not exhibited any indications of concrete degradation. The applicant also provided the following ground water chemistry data from UFSAR Section 2.4.13.2.

> Data from on-site wells of both pre-construction and construction periods compare closely with regard to chloride content. Preconstruction piezometer readings indicated concentrations from 10,000 to 25,000 ppm. Information obtained from samples taken throughout the site during dewatering at an average depth of 90 feet had 10,000 to 23,000 ppm chlorides and 1,000 to 4,000 ppm sulfides.

Water samples obtained from various on-site piezometers indicate pH values ranging from 5.5 to 7.1, and sulfates ranging from 387 to 2709 ppm (see Unit 1 UFSAR Table 2.4-3).

NUREG-1557 defines an aggressive environment for concrete to be pH less than 5.5, sulfates greater than 1500 ppm, and chlorides greater than 500 ppm. Since the St. Lucie ground water chemistry exceeds these levels, there is a potential for below-grade concrete structural components to degrade for the period of extended operation.

The staff also requested in RAI 3.5-9 that the applicant provide grade elevations and ground water level fluctuations at St. Lucie. In response, the applicant referenced UFSAR Section 2.5.4.11 which states that the existing grade around the unit at approximately elevation 0 feet was raised to elevation plus 18 feet with compacted fill. The ground water level was estimated to be the normal high water level in the Indian River at elevation plus 2 feet.

Fluctuations in the ground water are influenced by tidal changes in the Atlantic Ocean to the east, moderated by the Indian River to the west.

Due to the potential for an aggressive below-grade soil/ground water environment at St. Lucie, the applicant has committed, as shown in Table 3.5-2 of the LRA, to manage below-grade reinforced concrete structural components using the Systems and Structures Monitoring Program.

Steel. The applicant identified (1) loss of material of carbon steel in containment air, indoor and outdoor air, or exposed to borated water leaks, (2) loss of material of galvanized carbon steel exposed to an outdoor (wetted) environment or borated water leaks, and (3) loss of material of stainless steel in treated (borated) water as applicable aging effects for steel components in the containment structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel, galvanized carbon steel, and stainless steel components in the containment structure. However, the staff noted in RAI 3.5-2, that although loss of material is identified as an aging effect for galvanized carbon steel exposed to an outdoor (wetted) environment, no aging effects are identified in Table 3.5-2 for galvanized carbon steel components exposed to an outdoor environment that is not designated as being "wetted." As such, the staff requested that the applicant justify the conclusion that there are no applicable aging effects for galvanized carbon steel in an outdoor environment and to distinguish between a "wetted" outdoor environment and an outdoor environment.

In response to Item 1 of RAI 3.5-2, by letter dated September 26, 2002, the applicant stated the following.

> As noted in LRA Appendix C Section 5.1 (page C-11), galvanized steel is not susceptible to general corrosion except where buried, submerged, or subject to wetting other than humidity, such as salt spray. A "wetted" outdoor environment is one in which standing water accumulates or significant salt spray is present. Both wetted and non-wetted galvanized structures were identified by review of St. Lucie plant-specific operating experience and direct inspection of galvanized structures, and both types are identified in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93). Based on 25+ years of St. Lucie plant-specific operating experience, non-wetted galvanized structures, as defined in LRA Appendix C, Section 5.1 (page C-11), do not require aging management. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

The applicant's position regarding the potential for aging of wetted and nonwetted galvanized steel structures is based on over 25 years of operating experience. To further verify the applicant's conclusions, the staff conducted an onsite inspection of galvanized carbon steel components in an outdoor environment. The inspectors verified that the applicant's AMR findings for galvanized carbon steel components in an outdoor environment are correct. Inspectors determined that there is a difference between a "wetted" outdoor environment and a "nonwetted" outdoor environment, and that only those galvanized carbon steel components in wetted (significant salt spray or standing water) outdoor environment are susceptible to loss of material. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff generated Open Item 3.0.2.2-1 to track this issue. As a result of the satisfactory resolution of Open Item 3.2.2.2-1, the staff considers RAI 3.5-2 closed.

In RAI 3.5-6, the staff requested that the applicant provide further justification for concluding that stainless steel fuel transfer tube expansion bellows, located in a containment air environment, do not require aging management for cracking. By letter dated September 26, 2002, the applicant stated that the fuel transfer tube expansion bellows are not exposed to process fluid (i.e., borated refueling water). Also, the fuel transfer tube penetrations are not subject to elevated temperatures and, therefore, are not subject to thermal fatigue. The applicant concluded that there are no aging effects requiring management for fuel transfer tube expansion bellows in a containment air environment. The staff concurs with the applicant's findings that the environment, indicated above, is such that there are no aging effects requiring management for fuel transfer tube expansion bellows.

Elastomers (moisture barriers, seals). Table 3.5-2 of the LRA identifies loss of seal as an aging effect for elastomer components in the containment with the exception of the fuel transfer tube penetration flexible membranes in the annulus. The staff concurs with the applicant's identification of loss of seal as an applicable aging effect for elastomers associated with the primary containment pressure boundary components. However, in RAI 3.5-3, the staff requested that the applicant explain why there are no aging effects for the silicone fuel transfer tube penetration flexible membranes in the annulus. By letter dated September 26, 2002, the applicant stated the following.

> The fuel transfer tube flexible membranes provide a seal between each containment annulus and the outdoor environment where the fuel transfer tubes penetrate the shield buildings. These membranes serve as a ventilation boundary for Shield Building Ventilation. These flexible membranes are made of radiation resistant silicone rubber designed for the subject environment.
>
> As discussed in LRA Subsection 4.5.2 (page 4.5-2), the fuel transfer tube penetrations are not subject to elevated temperatures. Therefore, significant movements due to temperature fluctuations that could result in misalignment and loss of seal are not credible. Consequently, aging management of the seals is not required.

Since the fuel transfer tube penetrations are not subjected to elevated temperatures, the staff concurs with the applicant's evaluation of the potential aging effects for these flexible membranes.

Bronze/Graphite. Table 3.5-2 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates in the containment structure. In RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. By letter dated September 26, 2002, the applicant stated the following.

> As described in literature provided by Lubrite Technologies (formerly Merriman), Lubrite products are solid, permanent, completely self-lubricating, and require no maintenance. The Lubrite proprietary lubricant is a custom compound mixture of metals, metal oxides, minerals, and other lubricating materials combined with a lubricating binder. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed.
>
> As noted in LRA Subsection 2.3.1.6 (page 2.3-7), the Unit 1 SGs were replaced in 1997. The Lubrite plates for the SG upper lateral supports were also replaced. The original Lubrite plates showed no evidence of degradation.
>
> FPL performed an extensive search of industry and St. Lucie plant-specific operating experience utilizing various sources, including the INPO website. No reported instances of Lubrite plate degradation or failure to perform their intended function were identified. Consequently, there are no known aging effects that would lead to a loss of intended function. This position is consistent with that accepted by NRC as part of the Turkey Point Units 3 and 4 LRA review.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of Lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Item 2 of RAI 3.5-3 to be closed.

3.5.1.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in the containment structure.

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

The Boric Acid Wastage Surveillance Program, Chemistry Control Program, Periodic Surveillance and Preventive Maintenance Program, and Systems and Structures Monitoring Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff review of the common AMPs is in Section 3.0.5 of this SER. The staff evaluations of the ASME Section XI, Subsection IWE Inservice Inspection Program and the ASME Section XI, Subsection IWF Inservice Inspection Program are in Section 3.5.0.1 and Section 3.5.0.2, respectively of this SER.

3.5.1.3 Conclusions

The staff has reviewed the information in Section 3.5.1 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the containment structure will be adequately managed, so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2 Other Structures

3.5.2.1 Summary of Technical Information in the Application

The AMR results for structures outside containment are presented in Tables 3.5-3 through 3.5-16 of the LRA. Each of these AMR tables lists the (1) component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) AMPs. The structural components listed in Tables 3.5-3 through 3.5-16 of the LRA are in the following structures.

- component cooling water areas
- condensate polisher building
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fire rated assemblies
- fuel handling buildings

- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

A brief description of each of the above structures is provided in Section 2.4.2, "Other Structures," of the LRA. The materials of construction identified in Tables 3.5-3 through 3.5-16 of the LRA for each of the above structures are (1) steel, (2) concrete, (3) polymer, (4) elastomers, (5) earth fill, (6) caulking and sealants, (7) PVC, and (8) fire protection materials. These materials are exposed to outdoor, outdoor (wetted), indoor air-conditioned, indoor not-air-conditioned, buried, borated water leaks, treated water—borated, and raw water—saltwater.

3.5.2.1.1 Aging Effects

Tables 3.5-3 through 3.5-16 of the LRA identify the following applicable aging effects for components in structures outside containment.

- loss of material
- *change in material properties*
- cracking
- loss of seal

3.5.2.1.2 Aging Management Programs

Tables 3.5-3 through 3.5-16 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside containment.

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boraflex Surveillance Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the components in structures outside the containment will be adequately managed by these AMPs such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 Staff Evaluation

In addition to Section 3.5.2 of the LRA, the staff reviewed the pertinent information provided in Section 2.4.2, "Other Structures," and the applicable AMP descriptions provided in Appendix B to the LRA, to determine whether the aging effects for the components in structures outside the containment have been properly identified and will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the applicant's programs credited for the aging management of the components in structures outside the containments at St. Lucie. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the components in structures outside the containment.

3.5.2.2.1 Aging Effects

Concrete and Masonry Block Walls. Tables 3.5-3 through 3.5-16 of the LRA identify change in material properties (CMP), loss of material (LM), and cracking (CR) as applicable aging effects for unreinforced and reinforced concrete structural components in the following structures outside the containment.

- component cooling water areas—reinforced concrete equipment pedestals, walls, slabs below grating—indoor not-air-conditioned, outdoor (LM, CMP)
- fuel handling building — unreinforced concrete masonry block walls—indoor not-air-conditioned (CR)
- intake, discharge, and emergency cooling canals — concrete erosion protection—outdoor (LM); raw water—salt water (LM, CMP)
- intake structures — reinforced concrete slabs, walls, roofs, retaining walls—raw water - salt water (LM, CMP); reinforced concrete pump pedestals outdoor (LM, CMP)
- reactor auxiliary buildings — reinforced concrete below ground water (exterior)—buried (LM, CMP); unreinforced masonry block walls—indoor-air conditioned, indoor not-air-conditioned (CR)
- steam trestle areas — reinforced concrete below ground water (exterior)—buried (LM, CMP)
- ultimate heat sink dam — reinforced concrete walls, roofs, slabs—raw water salt water (LM, CMP)

For all other reinforced concrete structural components located above ground water in outdoor, sheltered, or buried environments, Tables 3.5-3 through 3.5-16 do not identify any applicable aging effects.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all of the concrete components in each of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete SCs is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for timely identification and correction of degraded conditions. In addition, the staff does not distinguish between the aging management requirements for general reinforced concrete structural components and those for reinforced masonry components. In RAI 3.5-1, the staff requested further information regarding the applicant's determination that management of concrete aging is required for only select components. In response to RAI 3.5-1, by letter dated September 26, 2002, the applicant stated that it disagrees with the staff's position regarding the aging management of concrete structures; however, the applicant decided that it will manage concrete aging for the period of extended operation. The applicant specifically stated that it will monitor concrete structural components for loss of material, cracking, and change in material properties through the Systems and Structures Monitoring Program. Since this commitment from the applicant covers all of the concrete components listed in Tables 3.5-3 through 3.5-16, this response is considered to be acceptable to the staff. RAI 3.5-1 is considered closed with respect to the concrete components in structures outside the containment. However, in response to RAI 3.5-12, the applicant stated that it does not plan to manage the aging of reinforced concrete masonry block walls for the period of extended operation. Reinforced concrete masonry block walls are found in the auxiliary building (LRA Table 3.5-12). As noted in Section 3.5.1.2.1, the staff does not distinguish between the aging management requirements for general reinforced concrete structures and those for reinforced concrete masonry block walls. In a letter dated December 23, 2002, the applicant modified its response to RAI 3.5-12 by stating that the System and Structures Monitoring Program will be used to manage cracking for reinforced concrete masonry block walls listed in LRA Table 3.5-12. The applicant's decision to manage cracking for reinforced concrete masonry walls is acceptable to the staff. Therefore, RAI 3.5-12 is considered to be closed.

For the below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/ground water environment is nonaggressive. The applicant, however, acknowledges that the soil/ground water environment at St. Lucie is potentially aggressive. This conclusion is based on pH, chloride, and sulfate levels measured in ground water samples at St. Lucie (UFSAR Section 2.4.13.2), which are listed above in Section 3.5.1.2.1 of this SER. Due to the potential for an aggressive below-grade soil/ground water environment at St. Lucie, the applicant has committed, as shown in Tables 3.5-3 through 3.5-16 of the LRA, to manage below-grade reinforced concrete structural components using the Systems and Structures Monitoring Program.

<u>Steel</u>. Tables 3.5-3 through 3.5-16 of the LRA identify loss of material and change in material properties as applicable aging effects for steel components exposed to the following environments.

- carbon steel—outdoor, indoor not-air-conditioned, borated water leaks, buried (LM)
- carbon steel—raw water (salt water), buried, outdoor, indoor not-air-conditioned (LM, CMP)
- carbon steel galvanized—outdoor (wetted), borated water leaks
- stainless steel—treated water (borated)

The staff concurs with the applicability of loss of material and change in material properties as an aging effect for steel components exposed to the above environments in structures outside the containment. However, the staff noted in RAI 3.5-2, that although loss of material is identified as an aging effect for galvanized carbon steel exposed to an outdoor (wetted) environment, no aging effects are identified in Tables 3.5-3 through 3.5-16 for galvanized carbon steel components exposed to an outdoor environment that is not designated as being "wetted." As such, the staff requested that the applicant justify the conclusion that there are no applicable aging effects for galvanized carbon steel in an outdoor environment and to distinguish between a "wetted" outdoor environment and an outdoor environment. The applicant's entire response to RAI 3.5-2 can be found in Section 3.5.1.2.1 of this SER. In summary, the applicant stated that galvanized steel is not susceptible to general corrosion except where buried, submerged, or subject to wetting other than humidity, such as salt spray. A "wetted" outdoor environment is one in which standing water accumulates or significant salt spray is present. In addition, the applicant stated that based on 25+ years of St. Lucie plant-specific operating experience, nonwetted galvanized structures do not require aging management. The applicant's position regarding the potential for aging of wetted and nonwetted galvanized steel structures is based on over 25 years of operating experience. To further verify the applicant's conclusions, the staff conducted an onsite inspection of galvanized carbon steel components in an outdoor environment. The inspectors verified that the applicant's AMR findings for galvanized carbon steel components in an outdoor environment are correct. Inspectors determined that there is a difference between a "wetted" outdoor environment and a "nonwetted" outdoor environment and that only those galvanized carbon steel components in wetted (significant salt spray or standing water) outdoor environment are susceptible to loss of material. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff generated Open Item 3.0.2.2-1 to track this issue. As a result of the satisfactory resolution of Open Item 3.2.2.2-1, the staff considers RAI 3.5-2 closed.

In RAI 3.5-3, the staff requested that the applicant justify its AMR conclusion regarding the carbon steel plate fire-sealed isolation joint. Contrary to other carbon steel components that are located in an indoor not-air-conditioned environment, the applicant did not identify loss of material as an applicable aging effect for the carbon steel plate fire-sealed isolation joint. In response to RAI 3.5-3, by letter dated September 26, 2002, the applicant stated the following.

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

Since aging of the carbon steel closure plate, which is provided on both sides of the fire-sealed isolation joint, will not cause a loss of intended function for the fire-sealed isolation joint, the staff concurs with the applicant's conclusion that there are no aging effects requiring management for the closure plates. Item 4 of RAI 3.5-3 is considered closed.

Fire Protection Materials. The fire protection materials identified in Table 3.5-8 of the LRA are (1) Marinite board, (2) Durablanket, (3) silicone, (4) Quelpyre, (5) ethafoam, (6) Dymeric sealant, (7) ceramic fiber, (8) Thermo-lag, (9) fire retardant coatings, (10) insulated blankets, (11) Cerablanket, and (12) aluminum. The applicant states that there are no aging effects for the above materials and therefore no AMPs are required for fire protection materials. The applicant's AMR conclusion for the fire protection materials is consistent with NUREG-1801 (GALL Report), which only calls for aging management of fire barrier penetration seals that are exposed to an outdoor environment. Since the fire protection materials identified in Table 3.5-8 of the LRA are exposed only to indoor environments, the staff concludes that these materials do not require aging management for the period of extended operation.

Miscellaneous Materials. The miscellaneous materials identified in Tables 3.5-3 through 3.5-16 of the LRA are (1) earth fill, (2) polyvinyl chloride (PVC), (3) silicone, (4) elastomers, (5) weatherproofing materials (caulking and sealants), and (6) boron impregnated polymer (boraflex). The applicant identified change in material properties as an applicable aging effect for the boraflex panels, and loss of seal for the elastomer door seals and weatherproofing. No aging effects are identified for either PVC or earth fill. The staff concurs with aging effects identified by the applicant for the boraflex panels, elastomer door seals, and weatherproofing. However, in RAI 3.5-5, the staff requested that the applicant justify its AMR conclusion regarding the earthen canal dikes in the intake, discharge, and emergency cooling canals. Earthen water-control structures are susceptible to loss of material and loss of form resulting from erosion, settlement, sedimentation, waves, currents, surface runoff, and seepage. By letter dated September 26, 2002, the applicant stated the following.

> As described in LRA Subsection 2.4.2.9 (page 2.4-12), the emergency cooling canal and the portion of the intake canal between the emergency cooling canal and the intake structures are in the scope of license renewal. Erosion of the associated earthen canal dikes is prevented by concrete erosion protection installed on the dike embankments. Aging management of the concrete erosion protection is performed by the Systems and Structures Monitoring Program (LRA Appendix B, Subsection 3.2.14, page B-57). Therefore, because the concrete erosion protection prevents aging of the earthen dikes, aging management of the earthen dikes is not required.

Since the earthen canal dikes are covered over by concrete, the staff concurs with the applicant's conclusion that aging management of the earthen dikes is not required. To further verify the applicant's conclusions, the staff conducted an inspection of the earthen canal dikes as part of the St. Lucie AMR inspection. The staff inspectors verified that in-scope portions of the earthen canal dikes are protected by concrete erosion protection. The inspection findings are documented in Inspection Report 50-335/2003-03 and 50-389/2003-03, dated March 7, 2003. The staff generated Open Item 3.0.2.2-1 to track this issue. As a result of the satisfactory resolution of Open Item 3.2.2.2-1, the staff concluded that loss of material and loss of form are not applicable aging effects for the earthen canal dikes and RAI 3.5-5 is considered closed.

3.5.2.2.2 Aging Management Programs

Tables 3.5-3 through 3.5-16 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment.

- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boraflex Surveillance Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

The Boric Acid Wastage Surveillance Program, Chemistry Control Program, Fire Protection Program, Periodic Surveillance and Preventive Maintenance Program, and Systems and Structures Monitoring Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff review of the common AMPs is in Section 3.0.5 of this SER. The staff evaluation of the ASME Section XI, Subsection IWF Inservice Inspection Program is presented above in Section 3.5.0.2 of this SER and the evaluation of the Boraflex Surveillance Program is in Section 3.5.0.3.

3.5.2.3 Conclusions

The staff has reviewed the information in Section 3.5.2 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes the applicant has demonstrated that the aging effects associated with the components in structures outside the containment will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB for the period of extended operation.

3.6 Aging Management of Electrical and Instrumentation and Controls

The applicant described its AMR results of electrical and instrumentation and controls (I&C) components requiring AMR at St. Lucie Units 1 and 2, in Section 3.6 of the LRA. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effect of aging on the electrical/I&C components will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.0 System-Specific Aging Management Program

In Section 3.6 of the LRA, the applicant states that there are no AMPs required for non-environmentally qualified (non-EQ) cables and connectors nor for uninsulated ground conductors. However, in response to the staff's RAI 3.6-1, the applicant proposed an AMP for some non-EQ cables and connectors. The staff's evaluation of the proposed AMP follows.

3.6.0.1 Non-EQ Cables and Connections Aging Management Program

The staff requested in a letter dated July 1, 2002, that the applicant provide a description of an AMP for accessible non-EQ electrical cables and connections (connectors, splices, and terminal blocks) within the scope of license renewal located in the containment exposed to an adverse localized environment caused by heat, radiation, or moisture. In a letter dated September 26, 2002, the applicant proposed an AMP for the non-EQ cables and connections for power and I&C that are within the scope of license renewal.

3.6.0.1.1 Summary of Technical Information in the Application

In a letter dated September 26, 2002, the applicant states that based on the original St. Lucie cable routing design, plant-specific operating experience, and periodic walkdowns that have been performed, there are no adverse localized environments caused by heat, radiation, or moisture present in areas where non-EQ cables and connections are located. As indicated in LRA Subsection 3.6.2.2 (page 3.6-9), the applicant performed an extensive review of St. Lucie plant operating experience associated with cables and connections, 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. 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 staff, the applicant proposed an AMP for non-EQ cables and connections in the St. Lucie containments. The non-EQ cables and connections managed by this program include those used in systems and components that are within the scope of license renewal.

3.6.0.1.2 Staff Safety Evaluation

The staff evaluated the proposed non-EQ cables and connections AMP. The evaluation of the proposed AMP focused on the program elements rather than details of specific plant procedures. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of this SER. To determine whether the AMP is adequate to manage the effect of aging so that there is reasonable assurance that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements.

Program Scope. The scope of inspection 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 the applicant's response to the staff's RAI 3.6-1, 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. These circuits are susceptible to induced currents from the high voltage power supply if insulation resistance diminishes. The staff noted that the scope of this AMP does not include the high range radiator monitoring cables. The staff met with the applicant on November 7, 2002. In this meeting, the staff requested the applicant to explain why high range radiator monitoring cables were not included in this AMP. The applicant states, in a letter dated November 27, 2002, that the containment radiation monitors (General Atomic, LRA Subsection 4.4.1.17, page 4.4-24) and associated cables (Unit 1—Boston Insulated Wire, LRA Subsection 4.4.1.6, page 4.4.-12, and Raychem Cables, LRA Subsection 4.4.1.7, page 4.4-13), both inside and outside containment at St. Lucie, are managed by the EQ program, and thus require no further discussion. The staff found the applicant's response acceptable because it explains why the high range radiator monitoring cables both inside and outside the containment are not included in the scope of this AMP. The staff also found the scope of the program acceptable because it includes cables and connections that are subject to potentially adverse localized environments that can result in applicable aging effects on these insulated cables and connections.

Preventive Actions. No actions are taken as part of this program to prevent or mitigate aging degradation, and the staff did not identify the need for such actions.

Parameter 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, or indication of possible age-related degradation of insulation that could affect these circuits. The staff found this approach acceptable because visual inspection and calibration programs provide means for monitoring the applicable aging effects for in-scope cables and connections.

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

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

The staff found the inspection technique for accessible non-EQ cables and connections acceptable on the basis that the AMP is focused on detecting change in material properties of the conductor insulation, which is the applicable aging affect when cables and connections are exposed to an adverse, localized environment. The staff also found that the normal calibration specified in the plant technical specification provides reasonable assurance that aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits will be detected prior to loss of cable intended function.

Monitoring and Trending. In the proposed AMP, the applicant states that trending actions are not included as part of this program because the ability to trend inspection results is limited. For visual inspection, the staff found the absence of trending acceptable because the ability to trend inspection results is limited and the staff did not see a need for such activities. However, for the calibration program, periodic review of calibration results and findings of the plant surveillance will identify the potential existence of aging degradation. Calibration results that are trendable provide additional information on the rate of degradation. In a meeting with the applicant on November 7, 2002, the staff requested that the applicant explain why the periodic review of calibration results was not addressed in the calibration program. In response to the staff request, in a letter dated November 27, 2002, the applicant states that although not a requirement in GALL Program XI.E2, test results of calibration reports for the source, intermediate, and power range detectors that are trendable will be evaluated to provide additional information on the rate of degradation for these cables. The staff found the applicant's response acceptable because calibration results that are trendable would provide additional information on the rate of degradation.

Acceptance Criteria. One acceptance criteria is that there are no unacceptable visual indications of cables and connection jacket surface anomalies. 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 cables associated with the source, intermediate, and power range neutron detectors, the acceptance criteria is specified in the plant procedures. These acceptance criteria are specified in terms of voltage and current limits. The staff found these acceptance criteria acceptable because they should ensure that the cables and connections intended functions are maintained under all CLB design condition for the period of extended operation.

Operating Experience. Operating experience has not identified the presence of adverse localized heat and radiation environments in the containment at St. Lucie. However, operating experience identified by the staff has shown that adverse localized environments caused by heat, radiation, or moisture for electrical cables and connections may exist next to or above within 3 feet of SGs, pressurizers, or hot process pipes, such as feedwater lines. The staff found that the proposed inspection and calibration program will detect the adverse localized environment caused by heat, radiation, or moisture of electrical cables and connections.

3.6.0.1.3 UFSAR Supplement

The applicant committed to provide a description of non-EQ cables and connections AMP to be added in the UFSAR supplements in Appendix A of the LRA. This was tracked as Confirmatory Item 3.6.2.1-1. In response to the confirmatory item, the applicant stated that it will revise the UFSAR supplement for St. Lucie Units 1 and 2 to incorporate the Containment Cable Inspection Program. For Unit 1, LRA Appendix A1, Subsection 18.1.7 and for Unit 2, LRA Appendix A2, Subsection 18.1.6, the applicant will add the following information.

Unit 1 Appendix A1

18.1.7 Containment Cable Inspection Program

The Containment Cable Inspection Program manages the potential aging of non-EQ cable and connections. This program includes non-EQ cables and connections associated with sensitive low-level signal circuits. The only non-EQ cables and connections associated with sensitive low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the neutron detectors. This AMP consists of periodic visual inspection of accessible non-EQ cables and connections within the scope of license renewal located in the containment that may be installed in adverse localized environments, and review of calibration test results for indication of age-related degradation of cables associated with the neutron detectors. The inspections will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

Unit 2 Appendix A2

18.1.6 Containment Cable Inspection Program

The Containment Cable Inspection Program manages the potential aging of non-EQ cable and connections. This program includes non-EQ cables and connections associated with sensitive low-level signal circuits. The only non-EQ cables and connections associated with sensitive low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the neutron detectors. This AMP consists of periodic visual inspection of accessible non-EQ cables and connections within the scope of license renewal located in the containment that may be installed in adverse localized environments, and review of calibration test results for indication of age-related degradation of cables associated with the neutron detectors. The inspections will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

The staff reviewed the proposed Sections 18.1.6 and 18.1.7 for the UFSAR (Appendices A1 and A2 of the LRA) and verified that the information provided in the UFSAR supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities, as required by 10 CFR 54.21(d).

3.6.0.1.4 Conclusions

The staff finds that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connections due to radiation and oxygen will be adequately managed so that there is reasonable assurance that the intended functions of these cables will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.1 Summary of Technical Information in the Application

3.6.1.1 Non-EQ Insulated Cables and Connections

In Section 3.6.1.1 of the LRA, the applicant described the process used to identify the applicable aging effects of the electrical/I&C components. The process is based on the U.S. Department of Energy (DOE) aging management guide. This DOE aging management guide provides a comprehensive compilation and evaluation of information on the insulated cables and connections, spliced connections, and terminal blocks. The electrical/I&C nonmetallic materials are also evaluated with the cable and connector materials in this DOE aging management guide. The DOE aging management guide evaluated the stressors acting on cable and connection components, industry data on aging and failures of these components, and the maintenance activities performed on cable systems. Also evaluated was the main subsystem within cables—including the conductors, insulation, shielding, tape wraps—and jacketing, as well as all subcomponents associated with each type of connection.

The applicant also identified, evaluated, and correlated the principal aging mechanisms and anticipated effects resulting from environmental and operating stresses with plant experience to determine whether the predicted effects are consistent with field experience. As such, the information, evaluations, and conclusion contained in the DOE aging management guide are used for the evaluation of aging effects.

The most significant and observed aging mechanisms for insulated cable and connections are listed in the DOE Cable Aging management guide, Table 4-18. The applicant used the aging mechanisms from that table as the starting point for identifying aging effects for insulated cables and connections (splices, terminal blocks, and connectors). The applicant presents the potential aging effects along with the applicable stressors that are evaluated for insulated cables and connections in Table 3.6-1 of the LRA.

3.6.1.1.1 Low-Voltage Metal Connector Contact Surfaces—Moisture and Oxygen

Aging Effects. The applicant states that the DOE Cable Aging management guide, Section 3.7.2.1.3, states that 3 percent of all low-voltage metal connector failures were identified as being caused by moisture intrusion. In each case, the source of moisture was precipitation. Based on the total number of reported connector failures in the DOE Cable Aging management guide, moisture intrusion accounted for only 10 failures in all of the operating plants in the United States.

In Table 3.6-2 of the LRA, the applicant indicates structures where electrical/I&C components may be exposed to moisture. The potential moisture sources from LRA Table 3.6-2 that are applicable to connectors at St. Lucie are precipitation and potential boric acid leaks.

Aging Management Program. The applicant states that all metal connectors are located in enclosures or protected from the environment with Raychem splices. Thus, aging effects related to moisture and oxygen do not require an AMP for low-voltage connectors at St. Lucie. The applicant also noted that electrical enclosures are treated as structural components and are discussed with each structure, as applicable, in Section 3.5 of the LRA.

3.6.1.1.2 Low-Voltage Metal Compression Fittings—Vibration and Tensile Stress

Aging Effects: The applicant states that the aging mechanism of mechanical stress will not result in aging effects requiring an AMP for the following reasons.

> Damage to cables during installation at St. Lucie is unlikely due to standard installation practices, which include limitations on cable pulling tension and bend radius. Even though installation damage is unlikely, most (including all safety-related) cables are tested after installation and before operation. Failures induced by installation damage generally occur within a short time after the damaged cable is energized.
>
> NRC resolution of License Renewal Issue No. 98-0013, which states, "Based on the above evaluation, the staff concludes that the issue of degradation induced by human activities need not to be considered as a separate aging effect and should be excluded from an AMR."
>
> Mechanical stress due to forces associated with electrical faults is mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature.
>
> Vibration is generally induced in cables and connections by the operation of external equipment, such as compressors, fans, and pumps. Vibration can affect cable connections at a running motor by producing fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Normally, there has to be some physical damage as well to have an effect (e.g., a nicked connector). Terminations at equipment are part of the equipment and are inspected and maintained along with the equipment. These terminations are not within the evaluation boundary for insulated cable and connections and are not included in the insulated cable and connection review.
>
> Manipulation of cables is not considered an aging mechanism since such manipulation occurs during maintenance activities. Such activities require post-maintenance testing to detect any deficiency in the cables. Any evidence of cable abnormalities would result in condition being addressed under the corrective program.

Aging Management Program. The applicant concludes that the aging mechanism of mechanical stresses are not aging effects requiring management based on the discussion above.

3.6.1.1.3 Medium-Voltage Cable and Connection Insulations - Moisture and Voltage Stress

Aging Effects. The applicant indicates, in Table 3.6-2 of the LRA, structures where electrical/I&C cable and connectors may be exposed to moisture. From the potential moisture sources identified in LRA Table 3.6-2, precipitation and standing water in the duct bank require further considered for medium-voltage insulation. The effects of moisture-produced water trees on medium-voltage cable were examined in Section 4.1.2.5 of the DOE Cable Aging management guide. Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture. These trees eventually result in breakdown of the dielectric materials and ultimate failure. The growth and propagation of water trees is somewhat unpredictable and few occurrences have been noted for cables operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cable with cross-linked polyethylene (XLPE) or high molecular weight polyethylene (HMWPE) insulation. However, some cables are located in structures exposed to outside ambient conditions and are evaluated for the potential of moisture-produced water trees.

The applicant also indicates that St. Lucie Units 1 and 2 medium-voltage applications, defined as 2 kV to 15 kV, use lead sheath cable to prevent effects of moisture on the cables. The applicant's cable specification for lead sheath power cables states that lead sheath cables are designed to be installed in wet environments for extended periods. In addition, the cable manufacturer's specification for lead sheath cables states that "... ethylene propylene rubber (EPR)/lead sheath cable is designed for applications in which liquid contamination is present and reliability is paramount. The sheath combined with overall jacket provides a virtually impenetrable barrier against hostile environment - liquids, fire, hydrocarbons, acids, caustic, sewage, etc." As an additional level of protection, underground medium-voltage cables are only routed in concrete-encased duct banks.

Aging Management Program. The applicant indicates that St. Lucie Units 1 and 2, medium-voltage applications, defined as 2 kV to 15 kV, use lead sheath cable to prevent effects of moisture on the cables. The applicant concludes that aging effect related to cable exposed to moisture and voltage stress do not require an AMP at St. Lucie.

3.6.1.1.4 Medium- and Low-Voltage Cable and Connection Insulation—Radiation and Oxygen

Aging Effects. The applicant states that DOE Cable Aging management guide, Section 4.1.4, Table 4-7, 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 to 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 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 operating dose shown in LRA Table 3.6-3 includes the maximum 60-year normal exposure for inside containment.

The applicant compares the maximum operating dose and the moderate damage doses in Table 3.6-3 of the LRA and indicates that all of the insulation materials included in this AMR will not exceed the moderate damage doses. The applicant concludes that aging effects caused by radiation exposure will not adversely affect the intended function of insulated cables and connections and electrical/ I&C penetration for the extended period of operation.

Aging Management Program. The applicant states that all of the insulation material will not exceed the moderate damage doses and concludes that aging effects related to radiation do not require an AMP for cables and connections included in the AMR.

3.6.1.1.5 Medium- and Low-Voltage Cable and Connection Insulation—Heat and Oxygen

Aging Effects. The applicant states that a maximum operating temperature was developed for each insulation type based on cable application at St. Lucie Units 1 and 2. The maximum operating temperature indicated in Table 3.6-4 in the LRA incorporates a value for self-heating for power applications combined with the maximum design ambient temperature.

The applicant used Arrhenius method, as described in EPRI NP-1558, "A Review of Equipment Aging Theory and Technology," to determine the maximum continuous temperature to which the insulation material can be exposed so that the material has an indicated "endpoint of 60 years." These limiting temperatures for 60 years of service are provided in Table 3.6-4 of the LRA.

The applicant then compares the maximum operating temperature to the maximum 60-year continuous use temperature for the various insulation materials and indicates that except for Hypalon, EPR, and EPDM used in power application, all of the insulation materials used in low- and medium-voltage power cables and connections can withstand the maximum operating temperature for at least 60 years.

For Hypalon, EPR, and EPDM cable insulation, the applicant states that the maximum operating temperatures, including self-heating, is 162 °F. The calculated maximum temperatures for a 60-year life is 154 °F for Hypalon, and 154.9 °F for EPR and EPDM, which are 8.0 °F and 7.1 °F, respectively, less than the maximum operating temperature. The applicant states that the difference is small and is considered to be within the conservatism incorporated in the maximum operating temperatures and the maximum 60-year continuous use temperature.

The applicant states, in LRA Table 3.6-4 that the maximum temperature for a 60-year life is based on a 50 percent retention-of-elongation for Hypalon, a 40 percent retention-of-elongation for EPR, and a 40 percent loss-of-elongation for EPDM. Since the cables and connections subject to an AMR either will not be subjected to accident conditions or are not required to remain functional during or after an accident, these values can be reduced much further without a loss of function. The Hypalon maximum temperature for 60-year life using 21 percent retention-of-elongation is 167 °F, which is greater than the maximum cable temperature of 162 °F. The EPR and EPDM maximum temperatures for 60-year life using 15 percent retention-of-elongation are 167 °F and 189 °F, respectively, which are also greater than the 162 °F maximum cable temperature.

The applicant states, based on conservatism as discussed above, there is reasonable assurance that Hypalon, EPR, and EPDM insulated cables will not thermally age to the point at which they will not be able to perform their intended function for the period of extended operation.

Aging Management Program. The applicant states that no AMP is required for medium- and low-voltage insulation (cable and connections) due to heat and oxygen.

3.6.1.1.6 Medium- And Low-Voltage Cable and Connection Insulation—Adverse Localized Environments

The applicant states that it performed an extensive review of the St. Lucie Nuclear Plant operating experience associated with cables and connection (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 or radiation that might be detrimental to cables and connections. In addition, walkdown of accessible non-EQ cables and connections within the scope of license renewal found no adverse localized environments caused by heat or radiation.

The applicant also states that the potential sources of adverse localized heat environments at St. Lucie Units 1 and 2 are from high temperature reactor coolant, main steam, feedwater, and blowdown system piping and components. Most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environment because of the following.

- The intake structures, steam trestle areas, Unit 1 component cooling water area, Unit 1 CST enclosure, ultimate heat sink dam, and yard structure are outdoor areas where cable and connections are not subject to adverse localized temperature and radiation effects.

- The turbine building is an outdoor area with no external walls or roofs.

- The reactor buildings, Unit 2 component cooling water area, Unit 2 CST enclosure, EDG buildings, and fuel handling buildings do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. The RABs contain steam blowdown system piping and components in limited areas.

- With regard to radiation, the only buildings with any appreciable radiation levels are the containments, the RABs, and the fuel handling buildings. However, non-EQ cables and connections in the RABs and fuel handling buildings are not located in areas that would be subject to adverse localized radiation environments during plant operation, including those postulated based on the conservative assumption of 1 percent failed fuel.

The applicant states that containment temperatures are monitored continuously and an average containment temperature is recorded daily, regardless of plant operating mode. For Unit 1, this average is taken from the containment fan cooler inlet temperature detectors (3 of 4 detectors are used). These detectors are located on the 45- and 62-foot elevations of the containment. For Unit 2, the average of the two containment air temperature detectors is used. These detectors are located on the 70-foot elevation of the containment. Per plant operating procedures, the recorded average temperature is required to be less than or equal to 115 °F. Since these temperature detectors are located at elevations that are greater than or equal to that of the electrical equipment within the scope of license renewal, the monitored temperatures are considered bounding.

The applicant states containment area radiation levels are monitored continuously by four radiation monitors located in various locations throughout each containment (these monitors are in addition to the safety related high range radiation, particulate, and gas monitors). Unit 1 UFSAR Section 12.1.4 and Unit 2 UFSAR Section 12.3.4 describes the area radiation monitoring system. High radiation activity in the vicinity of any of these containment monitors is indicated, recorded, and alarmed in the control room. Note that all cable and connection insulation materials that are located within the containment are the same as cable and connection insulation materials already included in the EQ program at St. Lucie. The area radiation monitoring system has 59 monitors (26 in Unit 1 and 33 in Unit 2) located throughout the RABs and fuel handling buildings. These monitors are indicated, recorded, and alarmed in the appropriate control room. Changes to the plant environment may be identified by routine operator walkdown and periodic health physics radiation monitoring (surveys of areas in the RAB and fuel handling building are conducted at least monthly, and in some cases daily or weekly). Additionally, all plant personnel are trained to use the plant's corrective action program if conditions adverse to quality, which would include abnormal environmental conditions, are observed. Any change in temperature that could adversely affect non-EQ cables and connections would be readily noticed. The same applies for radiation. The normal 40-year radiation doses are based on the assumption of operation with 1 percent failed fuel. This is conservative because St. Lucie Units 1 and 2 have never operated with more than one percent failed fuel. Therefore, changes in local dose rates that would affect the life of equipment would have to be so significant that they would be readily identified.

In addition, the applicant states that 60-year life maximum temperature and radiation values for non-EQ cable and connection insulation materials are also conservative. The typical "endpoint" for cable thermal aging data is 40 percent to 60 percent retention-of-elongation. Research funded by the NRC, and published in NUREG/CR-6384, determined that the retention-of-elongation of most cable insulation materials can be reduced to 0 percent, and the insulation will still be capable of withstanding a LOCA and remain functional. As the insulated cables and connections subject to an AMR will either not be subject to an accident environment or are not required to function after being subject to an accident environment, the endpoint chosen for this review is extremely conservative. The insulated cable and connection materials could be aged a great deal more, possibly to the point where retention-of-elongation reaches 0 percent, without loss of intended function. Preliminary results of the EQ research on low-voltage electrical cables were presented by Brookhaven National Laboratories at an NRC public meeting on March 19, 1999. Preliminary conclusion from LOCA tests 1, 2, and 3 of the NRC research program indicated that, "Electrical cable with insulation elongation-at-break values as low as 5 percent performed acceptable under accident conditions." Therefore, the useable 60-year life temperature for a typical cable insulation is significantly higher than the values shown in Table 3.6-4 of the LRA. Table 3.6-3 of the LRA shows that the radiation values that non-EQ and connection insulation materials can withstand are much greater than actual design values for the 60-year life of the plant.

The applicant concludes that based on the original St. Lucie Units 1 and 2 cable routing designs, plant-specific operating experience, and period walkdowns that have been performed, there are no adverse localized environments caused by heat or radiation present in areas where non-EQ cables and connections are located.

3.6.1.2 Uninsulated Ground Conductors

3.6.1.2.1 Aging Effects

The applicant states that the ground cable material used at St. Lucie Units 1 and 2 is copper. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong, and it is easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical-type connectors, which include compression-, bolted-, and wedge-type devices.

The applicant states that a review of available technical information regarding material aging revealed that there are no aging effects requiring management for copper grounding materials. In addition, a review of industry and plant operating experiences did not identify any failures of copper grounding systems due to aging effects.

3.6.1.2.2 Aging Management Program

The applicant states that based on industry and plant-specific experiences, no aging effects requiring management were identified for the plant grounding system. The applicant also reviewed industry and plant operating experience to ensure that no unique aging effects exist beyond those discussed in Section 3.6 for cables and connections.

3.6.2 Staff Evaluation

The staff evaluated the information on aging management presented in the LRA, Section 3.6.1, and in the applicant's response to the staff RAIs, dated November 27, 2002, to determine whether the aging effects for non-EQ insulated cables and connections have been properly identified and will be adequately managed consistent with its CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for aging effects and the applicant's AMP credited for the aging management of non-EQ insulated cables and connections at St. Lucie Nuclear Station. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the non-EQ insulated cables and connections (terminal blocks, connectors, and splices).

3.6.2.1 Non-EQ Insulated Cables and Connections

3.6.2.1.1 Low-Voltage Metal Connector Contact Surfaces—Moisture and Oxygen

Aging Effects. The potential aging mechanisms considered for low-voltage metal connector surfaces is corrosion due to moisture intrusion. Structures where electrical/I&C components may be exposed to moisture are indicated in the LRA Table 3.6-2. The potential moisture sources from this table that are applicable to connectors at St. Lucie are precipitation and potential boric acid leaks. Table 3.6-1 of the LRA indicates that increased resistance and heating, high resistance, and loss of circuit continuity are the potential aging effects for low-voltage metal connector contact surfaces and compression fitting. The staff concurred with the aging effects identified above by the applicant for the low-voltage metal connector surfaces. High resistance and loss of circuit continuity are the potential aging effects for low-voltage metal connector surfaces.

Aging Management Program. The staff finds that because low-voltage connectors are located in an enclosure or protected from the environment with Raychem splices, there is no aging effect related to moisture and oxygen, and an AMP for low-voltage connectors is not required.

Conclusion. On the basis of the staff's evaluation above, the staff concludes that the applicant has demonstrated that the aging effects associated with low-voltage metal connector contact surfaces will be adequately managed so that there is reasonable assurance that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.2 Low-Voltage Metal Compression Fitting—Vibration and Tensile Stress

Aging Effects. The aging mechanism of mechanical stress will not result in aging effects requiring management for the following reasons.

- Damage to cables during installation at St. Lucie is unlikely due to standard installation practice, which include limitation on cable pulling tension and bend radius.

- NRC resolution of License Renewal Issue No. 98-0013 states that the issue of degradation induced by human activities need not be considered as a separate aging effect and should be excluded from an AMR.

- Mechanical stress due to forces associated with electrical faults is mitigated by the fast action of circuit protective devices at high currents. However, the mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature.

- Vibration is generally induced in cables and connections by the operation of external equipment, such as compressor, fans, and pumps. Vibration can affect cable connections at a running motor by producing fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Normally, there has to be some physical damage as well to have an effect (e.g., a nicked connector). Terminations at equipment are part of the equipment and are inspected and maintained along with the equipment. These terminations are not within the evaluation boundary for insulated cable and connections and are not included in the insulated cable and connection review.

- manipulation of cables is not considered an aging mechanism since such manipulation occurs during maintenance activities. Such activities require post-maintenance testing to detect any deficiencies in the cables. Any evidence of cable abnormalities would result in the condition being addressed under the corrective action program.

Aging Management Program. Because mechanical stress will not result in aging effects, an AMP for low-voltage metal compression fittings is not required for St. Lucie.

Conclusion. On the basis of the staff's evaluation above, the staff concludes that damage to low-voltage metal compression fitting during installation, electrical faults, vibration, and manipulation of cables are not considered aging mechanisms that result in aging effects. The applicant has demonstrated that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.3 Medium-Voltage Cable and Connection Insulations—Moisture and Voltage Stress

Aging Effects. Structures where electrical/I&C cable and connectors may be exposed to moisture are indicated in Table 3.6-2 of the LRA. Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture. These trees eventually result in breakdown of the dielectric materials and ultimately failure. The growth and propagation of water trees is somewhat unpredictable and occurrences have been noted for cable operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cable with conductor insulation made by various organic polymers (e.g., XLPE and HMWPE). The staff concurs with the applicant's determination that formation of water trees are applicable aging effects for the inaccessible non-EQ medium-voltage cables caused by moisture and voltage stress.

Aging Management Program. St. Lucie Units 1 and 2 medium-voltage applications use lead sheath to prevent effects of moisture on the cables. The cable specification states that lead sheath cables are designed to be installed in wet environments for extended periods. In addition, the cable manufacturer specification for lead sheath cable states that "...EPR/lead sheath cable is designed for application in which liquid contamination is present and reliability is paramount. The sheath combined with the overall jacket provided a virtually impenetrable barrier against hostile environments - liquids, fire hydrocarbons, acids, caustic, sewage, etc." As an additional level of protection, St. Lucie underground medium-voltage cables are only routed in concrete encased duct banks.

The staff concludes that since the applicant uses lead sheath medium-voltage cables which are specifically designed for use in wet environments, an AMP to manage the water treeing for medium-voltage cable is not required.

Conclusions. On the basis of the staff's evaluation above, the staff concludes that the applicant has demonstrated that the aging effects associated with inaccessible medium-voltage cables will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.4 Medium- and Low-Voltage Cable and Connection Insulation—Radiation and Oxygen

Aging of Effects. Section 3.6.1.1.4 of the LRA evaluates the aging effects applicable for electrical components that can be expected to occur due to 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 to 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 LRA 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 is required for radiation.

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment. Conductor insulation materials used in cable and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is limited to a certain plant area that is significantly more severe than the specific service condition for the cables and connections. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Radiation-induced degradation in cable jacket and insulated materials produces change in organic material properties, including reduced elongation and tensile strength. Visible indication of radiative aging may include embrittlement, cracking discoloration, and swelling of the jacket and insulation material. The aging effects identified above require aging management. The purpose of the AMP is to provide reasonable assurance that the intended functions of electrical cables and connections exposed to adverse localized environments caused by radiation will be maintained consistent with the CLB through the period of extended operation.

For the St. Lucie units, the intake structures, steam trestle areas, Unit 1 component cooling water area, Unit 1 CST enclosure, ultimate heat sink dam, and yard structure are outdoor areas where cable and connections are not subject to adverse localized temperature and radiation effects. The turbine buildings are outdoor areas with no external walls or roofs. The reactor buildings, Unit 2 component cooling water area, Unit 2 CST enclosure, emergency diesel generator buildings, and fuel handling buildings do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. The RABs contain steam blowdown system piping and components in limited areas. With regard to radiation, the only buildings with any appreciable radiation levels are the containments, the RABs, and the fuel handling buildings. However, non-EQ cables and connections in the RABs and fuel handling buildings are not located in areas that would be subject to adverse localized radiation environments during plant operation.

The applicant concludes that because the maximum operating radiation dose to cable insulation will not exceed the moderate doses, no aging management is required for radiation. The applicant's conclusion is not consistent with the AMP and activities for electrical cables and connections exposed to localized environments caused by radiation as described in the previous LRAs that have been approved by the staff. The staff requested the applicant to provide a description of an AMP for accessible non-EQ electrical cables and connections (connectors, splices, and terminal blocks) within the scope of license renewal located in the containment exposed to an adverse localized environment caused by radiation or moisture.

The applicant responded in a letter dated September 26, 2002, stating that based on the original St. Lucie cable routing design, plant-specific operating experience, and periodic walkdowns, there are no adverse localized environments caused by heat, radiation, or moisture present in areas where non-EQ cables and connections are located. As indicated in LRA Section 3.6.2.2 (page 3.6-9), the applicant performed an extensive review of St. Lucie plant operating experience associated with cables and connections, 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. 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 staff, the applicant proposed an AMP 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 staff finds the applicant's response acceptable because it proposes an AMP that will manage the aging effects caused by heat, radiation, or moisture. The staff evaluated this AMP in Section 3.6.0.1 of this SER.

In a letter dated May 16, 2002, the NRC forwarded to the NEI and Union of Concerned Scientists, a proposed ISG on screening of electrical fuse holders. The staff position indicated that fuse holders should be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This position only applies to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered to be piece parts of the larger assembly and not subject to an AMR.

The intended functions of a fuse holder are to provide mechanical support for the fuse and to maintain electrical contact with the fuse blades or metal end caps to prevent the disruption of the current path during normal operating conditions when the circuit current is at or below the current rating of the fuse. Fuse holders perform the same primary function as connections by "providing electrical connections to specified sections of an electrical circuit to deliver rated voltage, current, or signals." These intended functions of fuse holders meet the criteria of 10 CFR 54.4(a). In addition, these intended functions are performed without moving parts or without a change in configuration or properties, as described in 10 CFR 54.21(a)(1)(i). The fuse holders into which fuses are placed are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of copper.

Operating experience as discussed in NUREG-1760 (Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants) identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. The final staff position on this issue is under development in discussions with NEI. In the meeting with the applicant on November 6, 2002, the staff requested that the applicant provide details of AMR of fuse holders, and commit to implement, at St. Lucie Units 1 and 2, the final resolution of the ISG.

In response to the staff request, in a letter dated November 22, 2002, the applicant states that with regard to the AMR of fuse holders, as stated in the applicant'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 (RGs) 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 RABs. These panels are enclosures that contain the fuse, 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, radiation, and heat. The AMR also addressed averse localized environments. As indicated above, the AMR concluded that there were no aging effects requiring management for electrical connections.

The applicant also stated that based on its 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 AMR are those associated with fuses that are not routinely removed for maintenance and/or surveillance. When these circuits need to be de-energized, power is removed at the safety-related power supplies (motor control centers, power panels, etc.). Based on the information provided above, the applicant concludes that there are no aging effects requiring management for fuse holders. However, in the meeting with the applicant on November 6, 2002, the staff has requested that the applicant make a commitment to implement the final resolution of the ISG regarding fuse holders currently under discussion with the industry. The applicant stated that it will address the revision to the ISG regarding fuse holders (when issued) as applicable to St. Lucie.

Operating experience as discussed in NUREG-1760 identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. On this basis, fuse holders (including both the insulation material and the metallic clamps) are subject to both an AMR and AMP for license renewal. Typical plant effects observed from fuse holder failure due to aging have resulted in challenges to safety systems, cable insulation failure due to over-temperature, failure of containment spray pump to start, a reactor trip, etc. Therefore, managing age-related failure of fuse holders would have a positive effect on the safety performance of a plant. INs 91-78, 87-42, and 86-87 are examples that underscore the safety significance of fuse holders and the potential problems that can arise from age-related fuse holders failure. Since the aging effects for fuse holders (metallic portions) were not adequately addressed and the ISG was not finalized at that time, the staff decided to follow up this issue as Open Item 3.6.2.1-1.

In response to the open item, in a draft response letter dated February 26, 2003, the applicant stated that at the NRC public meeting on November 6, 2002, FPL was requested to provide details of the St Lucie Units 1 and 2 AMR of fuse holders, and to provide a commitment to address an ISG document regarding fuse holders. Subsequent to that meeting, on March 4, 2003, the NRC issued ISG-5 on the identification and treatment of electrical fuse holders for license renewal. The staff position stated in ISG-5 is as follows.

> Consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders would be scoped, screened, and included in the aging management review (AMR) in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This staff position only applies to fuse holders that are not part of a larger assembly, but support safety-related and non safety-related functions in which the failure of a fuse precludes a safety function from being accomplished [10 CFR Part 54.4(a)(1) and (a)(2)]. Examples are fuses that are used as protective devices to ensure the integrity of containment electrical penetrations when they are challenged by electrical faults, or as isolation devices between Class 1E and non-Class 1E electrical circuits to ensure that the safety function is

not compromised as a result of faults in the non-Class 1E circuits. An appropriate aging management program (AMP) should be adopted to manage the effects of aging where necessary.

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 consistent with the ISG. The only fuse holders determined to require an AMR were those installed to address RGs 1.63 and 1.75 to provide double isolation for non safety-related loads powered from safety-related power supplies. These fuse holders are installed in isolation panels located in the RABs in rooms classified as "mild environment" areas (e.g., electrical equipment rooms, etc.). The aging effects associated with the isolation panel enclosures (NEMA Type 2, 4, and 12) are managed by the Systems and Structures Monitoring Program (LRA Appendix B, Subsection 3.2.14, page B-57). As provided in LRA Section 3.6 (pages 3.6-1 through 3.6-16), the AMR for connections (including the fuse holders in the panels above) addressed applicable aging mechanisms including moisture and oxidation, corrosion, chemical contamination, mechanical stresses including vibration and tensile stresses, electrical transients, thermal cycling, fatigue, radiation, and heat on the connecting surfaces. The AMR also addressed adverse localized environments. The AMR concluded that there were no aging effects requiring management for electrical connections, including the fuse holders associated with the panels noted above. Details of the AMR for the fuse holders are provided below.

Moisture, Chemical Contamination, Oxidation, Corrosion

As stated in LRA Subsection 3.6.1.1.1 (page 3.6-2) and DOE Cable Aging management guide, Section 3.7.2.1.3, 3 percent of all low-voltage metal connector failures were identified as being caused by moisture intrusion. In each case, the source of moisture was precipitation. Based on the total number of reported connector failures in the DOE Cable Aging management guide, moisture intrusion accounted for only 10 failures in all of the operating plants in the United States. The fuse holders at St. Lucie that require an AMR are protected from external sources of moisture by two barriers. For the first barrier, the panels in which the subject fuse holders are installed are located in rooms inside the RABs classified as "mild environment" areas. These rooms protect the panels from the weather, and there are no sources of potential mechanical system leakage in proximity to the panels. For the second barrier, the fuse holders are located in closed NEMA Type 2, 4, and 12 enclosures, some of which are double enclosures. With regard to internal moisture (i.e., formation of condensation), a review of St. Lucie plant-specific operating experience did not reveal any instance of aging as a result of the formation of condensation internal to the panels in the RABs.

For chemical contamination, the fuse holders are protected, as described above, by their location and design.

With regard to oxidation and corrosion, the St. Lucie fuse holders requiring an AMR are either manufactured by Bussmann (previously Underwriters Safety Device Co.) or General Electric Co. The Bussmann fuse holders are style J60030-1CR and the General Electric fuse holders are type EK-1D style 9F61AEB301. The clips of these fuse holders are manufactured from copper or copper alloy plated with a corrosion resistant material (tin or silver) to protect the base metal from oxidation and provide for low electrical resistance. The tin and silver plating process is used extensively in the industry to protect both ferrous and nonferrous surfaces from corrosion. Based upon recent inspections of the Bussmann fuse blocks performed the week of March 10, 2003, the surface condition of the fuse clips show no signs of corrosion and still retain their bright tin/silver surface finish even after 20 years of service. Additionally, there was no evidence of moisture. These fuse holders are representative of other low voltage fuse holders at St. Lucie. Because of the excellent corrosion resistance of these platings in an indoor environment, no corrosion rate data for indoor (i.e., sheltered) environment could be located. Note that silver is one of eight noble elements and as stated in Metal Handbook Ninth Edition, Volume 13, "Corrosion of Tin Alloys", page 793, "These metals are unique in their nobility and for the most part offer industry corrosion resistance unmatched in base metals and their alloys." Further, page 771, Table 1 of the same book provides some ASTM corrosion rate data of commercial tin exposed to atmospheric (i.e., outdoor, unsheltered) conditions that demonstrates its excellent corrosion resistance. In a rural outdoor environment, the average corrosion rate after 10 years was approximately 2 hundredths of a mil/year (0.00049 mm/yr). For a marine outdoor environment, the corrosion rate after 10 years was .09 mils/year (0.0023 mm/year). Even in these harsh outdoor conditions, the corrosion rate is very small. This data supports the conclusion that for an indoor sheltered environment the corrosion rate of these fuse clips is not significant. This conclusion is further supported by the material condition of the fuse holders recently inspected.

Therefore, oxidation and/or corrosion do not result in aging effects requiring management for St. Lucie fuse holders requiring an AMR.

Mechanical Stresses, Electrical Transients, Thermal Cycling, Fatigue

Mechanical stresses, electrical transients and thermal cycling associated with the fuse holders at St. Lucie, as stated in LRA Subsection 3.6.1.1.2, do not result in aging effects requiring management for the following reasons.

(1) Mechanical stress due to forces associated with electrical faults and transients is mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature.

(2) Vibration is induced in fuse holders by the operation of external equipment, such as compressors, fans, and pumps. Since there are no direct sources of vibration for the fuse holder panels, and the panels are mounted separately on their own support structure on concrete walls, vibration is not an applicable aging mechanism.

(3) By design and their location, the fuse holders are not subject to aging effects associated with thermal cycling.

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 surveillance. When these circuits need to be de-energized, power is removed at the safety related power supplies (motor control centers, power panels, etc.).

Radiation, Heat

The fuse holder panels are installed in rooms classified as "mild environment" areas where there are no significant sources of radiation or heat.

As an additional check, FPL reviewed IN 86-87, 87-42, and 91-78 for applicability to the fuse holders at St. Lucie.

For IN 86-87, the loose fuse holder was associated with a potential transformer (PT) circuit fuse on an emergency bus which blew when a breaker was racked out. Note that although the IN describes a loss of offsite power and reactor trip, neither was attributed to the blown fuse.

For IN 87-42, the failure was associated with poor PT fuse contact. In this case, the fuses have moveable contacts mounted to the PT fuse compartment door so that when the door is opened, the contacts disconnect.

For IN 91-78, the deformed fuse holder was associated with a closing coil circuit on a circuit breaker.

FPL does not consider the above INs applicable to the fuse holders requiring an AMR at St. Lucie because of differences in usage, design, and construction.

Based on the information provided above, FPL concludes that there are no aging effects requiring management for fuse holders requiring an AMR for St. Lucie Units 1 and 2.

Open Item 3.6.2.1-1 was related to the aging effects identified in ISG-5. The fuse holders include both the insulation material and metallic clamps. The EQ cables and connections AMP will manage the aging of insulation material but not the metallic portions. In the ISG, the staff indicates that the AMR for fuse holders (metallic clamps) needs to include the following stressors if applicable—fatigue, mechanical stress, vibration, chemical contamination, and corrosion. Where environments or operating conditions preclude such aging effects (e.g., fuse holders not subject to vibration from rotating machinery), they need not be addressed by the AMP. The applicant states that the only fuse holders that were not part of large, active assembly are those installed to provide double isolation for non safety-related loads powered from safety-related power supplies. The applicant addressed each aging effect identified in the ISG and provided technical justification of why an AMP for the metallic portions of these fuse holders is not required. The staff agreed with the applicant's determination that the environments and/or operating conditions of the fuse holders preclude the aging effects identified in ISG-5. The staff finds that an AMP for the metallic portions of fuse holders is not required. The applicant also reviewed IN 86-87, 87-42, and 91-78 to see if the aging effects identified in the INs were applicable to the fuse holders at St. Lucie. The applicant concluded, and the staff concurred, that the above INs are not applicable to the fuse holders at St. Lucie because of differences in usage, design, and construction. The staff, therefore, found the applicant's response to the open item acceptable. The staff considers Open Item 3.6.2.1-1 closed.

Low-Level Instrumentation Circuits. In the LRA, the applicant did not provide an AMP for non-EQ electrical cables used in low-level instrumentation circuits. Instead, it proposed visual inspection for detecting aging degradation of these cables from heat or radiation. Exposure of electrical cables to localized environments caused by heat or radiation can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation, since it may contribute to inaccuracies in instrument loop. Visual inspection may not be sufficient to detect aging degradation from heat and radiation in the instrumentation circuits with sensitive, low-level signal. Because low-level signal instrumentation circuits may operate with signals that are normally in the pico-amp range or less, they can be affected by extremely low levels of leakage current. These low levels of leakage current may affect instrument loop accuracy before the adverse localized environment that caused them produces changes that are visually detectable. Routine calibration tests performed as part of the plant surveillance test program can be used to identify the potential existence of this aging degradation. In letters to the applicant dated July 1 and July 18, 2002, (RAI Number 3.6-2), the staff requested the applicant to provide a description of the AMP that will be relied upon to detect this aging degradation in sensitive, low-level signal circuits.

In response to the staff's request, in a letter dated September 26, 2002, the applicant stated that the AMRs it performed on non-EQ cables and connections determined that there were no aging effects that require management for the extended period of operation. These reviews included an assessment of aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits. A review of plant-specific operating experience performed as part of these AMRs (see LRA Section 3.6.2.2, page 3.6-9), which included a review of instrument calibration results and discussions with St. Lucie plant maintenance and engineering personnel, indicated that no failures of cables and connections associated with sensitive, low-level signal circuits have occurred due to aging.

As stated in the applicant's response to the staff's RAI 3.6-1, the applicant states that the only non-EQ cables and connections associated with sensitive, low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the source, intermediate, and power range neutron detectors. The applicant does not consider an additional AMP to address sensitive, low-level signal circuits to be necessary for the following reasons:

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

- Twenty-six and nineteen years of operating experience at St. Lucie Units 1 and 2, respectively, have not identified the need for an AMP tailored for non-EQ cables and connections associated with sensitive, low-level signal circuits.

- The Electrical Cable and Termination Aging Management Guideline, SAND 96-0344 concludes in Section 1.4 that "....reliance on visual inspection techniques for the assessment of low-voltage cable and termination aging appears warranted since these techniques are effective at identifying degraded cables." The applicant also stated that additional review of other license renewal SERs indicates acceptance of visual inspection for managing aging of cables and connections.

Aging Management Program. However, based on discussion with the staff in a public meeting on September 4 and 5, 2002, the applicant has included activities in the AMP proposed in the response to RAI 3.6-1 to address aging of the sensitive circuits associated with the source, intermediate, and power range neutron detectors. The results of routine calibration tests for these circuits will be used to facilitate detection of adverse localized environments. The acceptability of the combined program is evaluated in the non-EQ cables and connections AMP.

Conclusions. Based on the review of the LRA and the applicant's response to the staff's RAIs, the staff concludes that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connections due to radiation and oxygen will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.5 Medium- and Low-Voltage Cable and Connection Insulation—Heat and Oxygen

Aging Effects. Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and changes in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation.

Section 3.6.1.1.5 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 medium- and low-voltage power cables and connections can withstand the maximum operating temperature for at least 60 years. Therefore, no aging effects were identified for medium- and low-voltage cable and connection insulation due to heat and oxygen.

The most common adverse localized environments are those created by elevated temperature. Elevated temperature can cause equipment to age prematurely, particularly equipment containing organic materials and lubricants. The effect of elevated temperature can be quite dramatic. The types of areas that are prone to high temperature include areas with high temperature process fluid piping and vessels, areas with equipment that operate at high temperature, and areas with limited ventilation. It is not clear to the staff that the Arrhenius method can be used to extend the qualified life of the insulation material exposed to elevated localized temperature conditions to 60 years. The applicant's conclusion is not consistent with the AMP and activities for electrical cables and connections exposed to adverse localized environments caused by heat, as described in the previous LRAs that have been approved by the staff. In a letter dated July 1, 2002, the staff requested that the applicant describe an AMP for accessible and inaccessible electrical cables and connections exposed to adverse localized environments caused by heat or moisture.

In response to the staff's request, in a letter dated September 26, 2002, the applicant stated that most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environments. The RABs do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. Although, the RABs contain blowdown system piping and components, the piping runs are limited to the mechanical penetration areas, and are not located near electrical cables and connections. Due to the absence of adverse localized environments caused by heat 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 the discussion with the staff, the applicant proposed an AMP for non-EQ cables and connections in the St. Lucie containments. The staff finds the applicant's response acceptable because it proposes an AMP that will manage the aging effects caused by heat, radiation, or moisture.

Aging Management Program. The staff has evaluated the non-EQ cables and connections AMP for cables and connections exposed to potential adverse localized environment caused by heat and oxygen. The acceptability of this program is evaluated in the staff SER Section 3.6.0.1.2 under Aging Management Program.

Conclusion. The staff concludes that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connection due to heat and oxygen will be adequately managed so that there is a reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.6 Medium and Low-Voltage Insulation (Cables and Connections) Adverse Localized Environments

The applicant stated that the design at St. Lucie does not result in adverse localized environments outside the containment. The staff has evaluated this in sections 3.6.2.1.4 and 3.6.2.1.5.

The staff concludes that the applicant has demonstrated that the aging effects of medium- and low-voltage insulation (cables and connections) due to adverse localized environments will be adequately managed so that there is a reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 Uninsulated Ground Conductors

3.6.2.2.1 Aging Effects

The ground cable material used at St. Lucie Units 1 and 2 is copper. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong, and it is easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical-type connectors, which include compression-, bolted-, and wedge-type devices.

The applicant has reviewed the available industry technical information regarding material aging and has determined that there are no aging effects requiring management for copper grounding materials. In addition, the applicant has reviewed the industry and plant operating experience and did not identify any failures of copper ground system due to aging affects. Therefore, based on industry and plant-specific experience, no aging affects requiring management were identified for the plant grounding system. The staff concurs with the applicant that there are no aging effects identified for copper grounding material because copper has high corrosion resistance and operating experience did not identify any failure of copper ground systems.

3.6.2.2.2 Aging Management Program

The staff agrees with the applicant that no AMP is required for the uninsulated ground conductor because no aging effect is identified for uninsulated ground conductors.

3.6.3 Conclusions

The staff reviewed the information provided in Sections 3.6.1.1.1, 3.6.1.1.2, 3.6.1.1.3, 3.6.1.1.4, 3.6.1.1.5, 3.6.1.1.6, and 3.6.1.2 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that the applicant has demonstrated that the aging effects associated with non-EQ cables and connections will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4 Station Blackout System

3.6.4.1 Summary of Technical Information in the Application

By a letter dated April 1, 2002, the staff issued a staff position to NEI which clarified the use of an alternate AC power source within the context of the Station Blackout (SBO) Rule and stated 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 LRAs that are currently under review, such as St. Lucie Units 1 and 2. Consistent with the staff's position described in the aforementioned letter, the staff requested the applicant, in RAI 2.1-2, to describe the process it used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3). As part of the response, the staff requested that the applicant (1) list those additional SSCs included within scope, (2) list those SCs for which AMRs were conducted, and (3) describe the AMPs that will be credited for managing the identified aging effects. In a letter dated September 26, 2002, the applicant responded that restoration of offsite power is not relied on to meet the requirements of the SBO Rule for St. Lucie. However, based on the staff guidance provided in the April 1, 2002, letter, and RAI 2.1-2, the applicant 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.

The applicant stated that additional components included in the scope of license renewal as meeting the scope criteria of 10 CFR 54.4(a)(3) for restoration of offsite power are as follows.

- circuit breakers and switches to connect the startup transformer circuits to the grid
- batteries and DC controls associated with startup transformer circuit breakers
- startup transformers
- non safety-related 4.16 kV switchgear
- DC control and power (lead sheath) cables
- all aluminum alloy conductor (Type AAAC) transmission conductors between the startup transformers and circuit breakers
- high-voltage insulators associated with the transmission conductors
- switchyard bus and connections between the startup transformers and circuit breakers

- 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 non safety-related 4.16 kV switchgear do not require an AMR 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.

3.6.4.1.1 Type AAAC Transmission Conductors

The applicant states that 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.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent 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 percent loss of composite conductor strength of an 80-year-old transmission conductor. Assuming a 30 percent loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength.

Based on the above, the applicant states that 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 the applicant 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. The applicant states that it also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for transmission conductors. This review included nonconformance 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.

3.6.4.1.2 High Voltage Insulators

The applicant states that 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 experience. Therefore, surface contamination of St. Lucie Units 1 and 2 high-voltage insulator 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 strained and suspended 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 swing 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 loss of material due to wear is possible, industry experience has shown that if they begin to swing in a substantial wind, the swinging will stop when the wind subsides. 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 document 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 nonconformance 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.

3.6.4.1.3 Switchyard Buses and Connections

The applicant states that switchyard buses and connections are constructed of the following material.

- 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, the applicant performed a review of industry experience. This review included NRC generic communications and industry operating experience related to switchyard buses and connections. The applicant identified no documents involving switchyard buses and connections.

The applicant also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for switchyard buses and connections. This review included nonconformance 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. The applicant identified no unique aging effects for this review beyond those discussed above.

3.6.4.1.4 Nonsegregated-Phase Bus

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

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

The applicant performed an AMR for non-segregated phase buses. The applicant stated that aging effects for the nonsegregated-phase buses requiring evaluation are those associated with temperature, precipitation, and vibration.

The only material identified 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 rated for 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 rated for 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, the applicant concluded that 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 with 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, the applicant has not observed loss of material due to corrosion. Therefore, the applicant concluded that 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, the applicant performed a review of industry experience. This review included NRC generic communications and industry operating experience related to nonsegregated-phase buses. The applicant identified following documents related to nonsegregated-phase buses in its 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

The applicant identified no unique aging effects in the above documents beyond those discussed in this section.

The applicant also reviewed St. Lucie operating experience 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, the applicant conducted interviews with responsible engineering personnel to assess aging effects for the non-segregated phase buses. The applicant identified no unique aging effects from this review beyond those discussed above.

3.6.4.2 Staff Evaluation

This section provides the staff's evaluation of those SBO electrical components within the scope of license renewal and requiring an AMR. The staff reviewed this section to determine whether the applicant has demonstrated that the aging effects associated with SBO of the systems and components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4.2.1 Type AAAC Transmission Conductors

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 effects 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.

NESC requires that tension on installed conductors be a maximum of 60 percent 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 percent loss of composite conductor strength of an 80-year-old transmission conductor. Assuming a 30 percent loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength. This is further supported by the fact that the applicant 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, the applicant performed a review of industry experience. This review included the staff generic communications and industry operating experience related to transmission conductors. The applicant states that it also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for transmission conductors. This review included nonconformance 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.

Based on the materials, NRC generic communications, and St. Lucie operating experience, there are no aging effects requiring aging management for transmission conductors for the period of extended operation. The staff agrees with the applicant that no AMP is required for transmission conductors.

3.6.4.2.2 High Voltage Insulators

The 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 experience. Therefore, surface contamination of St. Lucie Units 1 and 2 high voltage insulator 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 strained and suspended 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 swing 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 loss of material due to wear is possible, industry experience has shown that transmission conductors do not normally swing and that if they begin to swing in a substantial wind, the swinging will stop when the wind subsides. 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, the applicant performed a review of industry experience. 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.

The applicant also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for transmission insulators. This review included nonconformance 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.

On the basis of its review of industry information, NRC generic communications, and St. Lucie operating experience, the staff concludes that there are no aging effects requiring aging management for high voltage insulators for the period of extended operation. The staff agrees with the applicant that no AMP is required for transmission insulators.

3.6.4.2.3 Switchyard Buses and Connections

The switchyard buses and connections are constructed of the following material.

- 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, the applicant performed a review of industry experience. This review included NRC generic communications and industry operating experience related to switchyard buses and connections. The applicant identified no documents involving switchyard buses and connections.

The applicant also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for switchyard buses and connections. This review included nonconformance 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. The applicant identified no unique aging effects for this review beyond those discussed above.

On the basis of its review of industry information, NRC generic communications, and St. Lucie operating experience, the staff concludes that there are no aging effects requiring aging management for switchyard buses and connections for the period of extended operation. The staff agrees with the applicant that no AMP is required for switchyard buses and connections.

3.6.4.2.4 Nonsegregated-Phase Bus

Bus ducts exposed to appreciable ohmic or ambient heating during operation may experience loosening of bolted connections resulting from the repeated cycling of connected loads or the ambient temperature environment. This phenomenon can occur in heavily loaded circuits (i.e., those exposed to appreciable ohmic heating). Sandia 96-0344 identified instances of terminations loosening at several plants due to thermal cycling. Information Notices 2000-14 provides examples that underscore the potential problem that arise from the thermal cycling of connection bolts.

Choric water leakage through inadequately caulked insulator mounting holes and improperly compressed gasket can cause degradation of the insulator metal inserts and insulator material between these inserts. Information Notice (IN) 98-36 notified the licensees of these inadequate maintenance activities.

During a conference call on May 5, 2003, the staff requested the applicant to review the IN 98-36, "Inadequate or Poorly Controlled, Non-Safety Related Maintenance Activities Unnecessary Challenged Safety Systems" and IN 2000-14, "Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power" for applicability at St. Lucie.

The applicant responded that IN 98-36 notified licensees of various inadequate maintenance (e.g., failure to install gaskets or caulking of outdoor components) practices in the industry which resulted in moisture intrusion and challenges to safety related systems. The silicon (silicon rubber) utilized in the St. Lucie plant design serves the purpose of electrical insulation, not weather proofing. Therefore, IN 98-36 is not applicable to St. Lucie and the applicant did not identify any additional effects other than those previously evaluated.

IN 2000-14 informed licensees of a transient at Diablo Canyon nuclear plant that was caused by a failure of a bus bar overheating at a splice joint. Potential causes of this failure included inconsistent silver plating of aluminum bus bars, currents approaching bus capacity, undersized splice plates, torque relaxation of connecting bolts, and undetected damage from a 1995 explosion of Auxiliary Transformer 1-1. The applicant stated that design of St. Lucie is different to that of Diablo Canyon. The key differences are as follows:

- The St. Lucie equipment specification required all bus bars and splice plates to be copper and all contact surfaces to be silver plated. Because they are copper, they are less susceptible to contraction and expansion experienced by the aluminum buses at Diablo Canyon.

- The non-segregated phase 4.16 kV buses at St. Lucie operate at approximately 47% of their load rating. The Diablo Canyon buses are routinely loaded to 93% capacity.

- St. Lucie buses have nearly a full face splice connection area.

- The St. Lucie equipment specification specifies the use of Belleville washers with half inch bolting hardware. These washers are superior to the split washers utilized at Diablo Canyon.

The staff noted that industry operating experience (IN 89-64) shows that insulated medium-voltage buses can experience catastrophic failures if they are not periodically inspected and maintained free of moisture and debris. Failures of medium-voltage buses have occurred at the Palo Verde, Kewaunee, Millstone, and Sequoyah Plants. The failure of medium-voltage buses was attributed to the cracking of bus bar insulation combined with the accumulation of moisture or debris in the bus bar housing. Cracked insulation in the presence of moisture or debris provided phase-to-phase or phase-to-ground electrical tracking paths, which resulted in catastrophic failure of the buses. Bus failures have led to loss of power to electrical loads, caused subsequent reactor trips, initiated unnecessary challenges to plant safety systems.

By the letter dated May 12, 2003, the staff requested a clarification from the applicant regarding industry operating experience with non-segregated phase buses. The staff asked the applicant whether the bus bars at St. Lucie are insulated, explain why failure of insulation of bus bars is not a concern at St. Lucie. The applicant responded that Information Notice 89-64 was issued to address Noryl insulated medium voltage bus bars failures that occurred at several other nuclear facilities. The failures identified in Information Notice 89-64 were attributed to cracking of the Noryl bus bar insulation in combination with the accumulation of moisture or debris in the bus duct housings that provided a tracking path to ground. Noryl is the General Electric Trademark name for a plastic type electrical insulation material. The non-segregated buses at St. Lucie plant use silicone rubber for the bus bar insulation which has proven to be a good insulating material by providing more than twenty six years of trouble free service. No problems of the type noted in Information Notice 89-64 have occurred at the St. Lucie plant.

In its supplemental response to RAI 2.1-2, dated June 10, 2003, the applicant stated the following:

> An inspection of the non-segregated bus ducts at St. Lucie Plant was performed circa 1992. This inspection verified that the interior of the non-segregated bus ducts was clean and dry. There was no evidence of moisture intrusion or condensation present inside the bus ducts and no deterioration of the busbar insulation was noted.

The bus bars inside the bus duct are spaced 5.38" from each other and 4.62" from the bus duct. From Paschen's curve for electrical breakdown in air, a useful guideline is that one inch of spatial separation is required for each 10,000 volts of potential. For the 4.16KV voltage present at St. Lucie Plant, a spatial separation of 1" would be sufficient to prevent a fault to ground or a fault between phases. Therefore, even with no insulating material on the bus bars, with the spatial separation of 5.38" between phases and 4.62" between phase and ground in the St. Lucie bus ducts, no electrical breakdown would occur. The St. Lucie plant bus ducts are designed to prevent moisture from entering the bus work. In addition, thermostatically controlled heaters are provided to maintain the temperature inside the duct work at between 80°F and 110°F to prevent condensation formation. The applicant then concluded that the failure mechanism identified with Noryl insulated bus bars in medium voltage non-segregated bus ducts as described in IN 89-64 is not applicable to the St. Lucie Plant.

The staff also requested the applicant to describe the design of the non-segregated bus duct system at St. Lucie and explain why accumulation of water, dust or debris is not a concern at St. Lucie. The applicant replied that the non-segregated bus ducts at St. Lucie plant are designed to provide a weather resistant enclosure that minimizes the potential for moisture and dust/particulate intrusion. These ducts are constructed of individual steel sections, approximately 6 to 8 feet in length, joined together with collars that are bolted to the individual bus duct sections. The collars are provided with channels that overlap the joints. Joints contain sponge strip or cement materials to provide a weather tight seal. The bus ducts are designed to minimize the potential for moisture intrusion by minimizing joints/seams. As such, the top and sides of the duct assembly are constructed of a single piece. Recessed bolted covers on the bottom of the bus ducts provide access for maintenance or repairs, if required. The bus ducts are provided with ventilation openings located at the top and with heaters at the bottom. The heater assemblies and vents are spaced at approximately 16 foot intervals along the length of the ducts. However, their locations on the ducts are offset from each other such that bus duct vents are spaced approximately 8 feet from the heaters. The bus ducts are provided with no openings other than for access through grillwork for the heaters located at the bottom. The ventilation openings at the top allow the exit of warm air, but exclude the entry of rain or debris by means of a labyrinth design. A filter assembly is provided beneath the heater sections of the bus duct to prevent intrusion of dust or particulate matter inside the bus ducts. The bus bars internal to the bus duct sections are constructed of copper and are provided with silicone insulating material. The bus bars are insulated from the bus duct by individual ceramic insulators that are mounted in a steel framework inside the bus duct. Past inspections of the non-segregated bus ducts has verified that the interior was clean and dry. There was no evidence of moisture intrusion or condensation present inside the bus ducts and no deterioration of the bus bar insulation was noted. The applicant concluded that the accumulation of water and debris inside the non-segregated bus ducts, as described in IN 89-64, is not a concern at St. Lucie plant.

In May 9, 2003 conference call between the staff and the applicant, the applicant indicated that it will revise the Table 2.1-8 of the September 26, 2002, response to include the non-segregated bus ducts to be included in the System and Structure Monitoring Program. This AMP manages the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties for the system and structures including non-segregated bus ducts. The staff asked the applicant if the program will inspect the waterproofing material for the non-segregated bus ducts. The applicant responded that the non-segregated bus duct is a sealed assembly that is designed to prevent the entry of water or debris into the bus ducts. More than twenty-six years of operating experience at St. Lucie plant demonstrates the success of the bus duct design to prevent moisture intrusion. The only waterproofing material in the bus duct (i.e., seals) is the sponge strip/cement material that is installed in the coupling collar channels that *joins the individual bus duct sections together. These coupling collars are an integral part of* the bus and are not designed for periodic removal for inspection. Removal of the collars would require disassembly of the ducts and disturb the watertight integrity of the bus duct. Any moisture intrusion into the bus duct by way of the coupling collar and past the seal would come out at the low point of the bus at the nearest heater. This would be evident to operations department personnel or system engineering personnel during their system walk-down inspections. No further actions are considered necessary with respect to inspection of watertight seals for the bus ducts.

The staff held a meeting with the applicant on May 21, 2003, to seek additional clarification of the aforementioned response pertaining to the non-segregated phase bus AMR. In the meeting, the staff indicated that the staff's acceptance of the applicant's conclusions regarding aging of the non-segregated bus is contingent upon resolution of the following:

- Verification of the insulating material aging properties (i.e., confirmation from vendor or verification of similarity analysis – comparison of chemical composition, etc.)

- Verification that based upon the bolting duty cycle, loss of pre-load of bolted splice connections will not occur in 60 years.

- Verification that current periodicity of heater filter replacement is adequate (i.e., meets vender recommendations) and provisions of a method of verifying the heaters are functional.

The staff also indicated that, as an acceptance alternative to the above, the applicant could propose an AMP.

In a letter dated June 10, 2003, the applicant committed to an AMP. Specifically, the applicant agreed to perform periodic visual internal inspections of a representative sample of the non-segregated phase buses at St. Lucie Units 1 and 2. These inspections will be conducted prior to the end of the current license periods and at 10 years interval thereafter. These inspections will include a visual inspection of the bus bar insulation for age-related defects (e.g., discoloration, cracking) and an inspection of the interior of the bus ducts for moisture or dust/debris. Additionally, these inspection will include verification of a representative sample of the bus bar bolting torque values. The inspection of the non-segregated phase buses will be included with the commitments to enhance the Periodic Surveillance and Preventive Maintenance Program described in the revised UFSAR Supplement (LRA appendix A) transmitted by the applicant letter L-2003-070 dated March 28, 2003.

On the basis of the staff's review of the applicant's commitment as described above, the staff concluded that the aging effects of non-segregated phase buses will be adequately managed so that there is reasonable assurance that the intended function(s) of components/systems will be maintained consistent with the CLB for the period of extended operation.

3.6.4.3 Conclusions

The staff reviewed the information provided in the LRA, the applicant's responses to the staff's request for additional information, and NRC generic communication. On the basis of this review and the above evaluation, the staff finds that the applicant has demonstrated that the aging effects associated with Station Blackout components/systems will be adequately managed so that there is reasonable assurance that the intended function(s) of components/systems will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

4. TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

In Section 4.1 of the LRA, the applicant describes its identification of time-limited aging analyses. The staff reviewed this section of the LRA to determine whether the applicant has identified the time-limited aging analysis (TLAAs), as required by 10 CFR 54.21(c).

4.1.1 Summary of Technical Information in the Application

The applicant evaluated calculations for St. Lucie Units 1 and 2 against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant indicated that calculations that meet the six criteria were identified from the technical specifications (TS), updated final safety analysis reports (UFSARs), and docketed licensing correspondence. The applicant identified the following TLAAs in Table 4.1-1 of the LRA.

- reactor vessel neutron embrittlement, including analyses for upper-shelf energy (USE), pressurized thermal shock (PTS), and pressure-temperature (P-T) limits
- metal fatigue, including analysis of American Society of Mechanical Engineers (ASME) Section III Class 1 components, ASME Class 2 and 3 components and American National Standards Institute (ANSI) B31.1 components
- environmental equipment qualification calculations
- containment penetration fatigue analyses
- leak-before-break (LBB) analyses
- crane load cycle limit
- Unit 1 core support barrel (CSB) repair fatigue analysis
- Unit 1 core support barrel (CSB) repair plug preload relaxation
- Alloy 600 instrument nozzle repairs

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 that were based on a TLAA, as defined in 10 CFR 54.3, were identified.

4.1.2 Staff Evaluation

As indicated by the applicant, TLAAs are defined in 10 CFR 54.3 as analyses that meet the following six criteria.

(1) involve systems, structures, and components within the scope of license renewal, as delineated in Section 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term, for example, 40 years

(4) Are determined to be relevant by the licensee in making a safety determination

(5) involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in Section 54.4(b)

(6) are contained or incorporated by reference in the current licensing basis (CLB)

Table 4.1-1 of the LRA did not identify pipe break postulation based on cumulative usage factor (CUF) as a TLAA. Section 3.6.2.2.1 of the Unit 2 UFSAR describes the criteria used to provide protection against pipe whip inside the containment. A part of the criteria specifies the postulation of pipe breaks at locations where the CUF exceeds 0.1. Although the fatigue usage factor calculation was identified as a TLAA, the pipe break criterion was not identified as a TLAA. However, the usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA, as specified in 10 CFR 54.3, and, therefore, the staff considers the associated criteria for pipe break postulation a TLAA. In the staff's request for additional information (RAI) 4.1-1, it requested that the applicant provide a description of the TLAA performed to address the pipe break criteria for St. Lucie Unit 2. The staff also requested the applicant to identify any pipe break postulations based on CUF at Unit 1 and describe the TLAA performed for these locations.

The applicant's October 10, 2002, response indicated that pipe breaks had been postulated in Class 1 piping at locations where the CUF exceeds 0.1 at Unit 2. The applicant also indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded in 60 years of plant operation. Therefore, the CUF calculations which form the basis for the Unit 2 pipe break postulations remain valid for the period of extended operation. The applicant's evaluation provides an acceptable TLAA for Unit 2 in accordance with the requirements of 10 CFR 54.21(c). The applicant indicated that Unit 1 does not use CUF values from the fatigue analysis to determine postulated pipe break locations, and, therefore, the Unit 1 pipe break criteria do not meet the definition of a TLAA, as provided in 10 CFR 54.3. The staff agrees with the applicant's conclusion.

Table 4.1-1 of the LRA did not identify fatigue of the reactor coolant pump (RCP) flywheel as a TLAA. In RAI 4.1-1, the staff asked the applicant to indicate whether fatigue crack growth calculations were performed for the Unit 1 and 2 RCP flywheels.

The applicant's October 10, 2002, response indicated that a reference to RCP flywheel crack growth calculations was found in Section 5.5.5.3 of the Unit 1 UFSAR. According to the applicant, RCP flywheel crack growth calculations indicate that the number of starting cycles required to cause a reasonably small crack to grow to critical size is more than 100,000. The applicant indicated that the number of starting cycles required to cause a crack to grow to critical size is far greater than the number of expected RCP pump starts for the period of extended operation. Therefore, the crack growth evaluation remains valid for the period of extended operation. The staff finds the applicant's flywheel crack growth evaluation meets the definition of a TLAA, as provided in 10 CFR 54.3. The applicant's evaluation, described above, provides an acceptable TLAA for the Unit 1 RCP flywheel crack growth calculation in accordance with the requirements of 10 CFR 54.21(c). The applicant indicated that a review of the Unit 2 licensing basis documentation did not identify or reference fatigue crack calculations for the flywheels. Therefore, there are no TLAAs associated with the Unit 2 RCP flywheels.

4.1.3 Conclusions

The staff has reviewed the information provided in Section 4.1 of the LRA. The staff concludes that, with the inclusion of the pipe break criteria for Unit 2 and the RCP flywheel crack growth analysis for Unit 1, the applicant has provided an acceptable list of TLAAs as defined in 10 CFR 54.3, and that no 10 CFR 50.12 exemptions have been granted on the basis of a TLAA, as defined in 10 CFR 54.3.

4.2 Reactor Vessel Neutron Embrittlement

The application includes three TLAAs for evaluation of the reactor vessel (RV) beltline materials, including (1) calculation of the end-of-extended-life Charpy USE value (C_vUSE values) for each beltline material, (2) calculation of the end-of-extended-life PTS reference temperature (RT) value (i.e., RT_{PTS} values) for each beltline material, and (3) a calculation of P-T limits. Each analysis has been updated to consider 20 years of additional plant operation at power. The TLAAs take into account the effects of the additional extended-operating-period neutron irradiation on the previous calculated end-of-life C_vUSE, the RT_{PTS}, and P-T limit values for the Units 1 and 2 RVs and conservatively base the evaluations through 54 effective full power years (EFPY) of power operation.

4.2.1 Upper-Shelf Energy

Appendix G to 10 CFR Part 50 requires that RV beltline materials have C_vUSE values in the transverse direction for the base metal and along the weld for the weld material according to the ASME Code, of no less than 75 foot-pounds (ft-lb) (102 J) initially, and must maintain C_vUSE values throughout the life of the vessel of no less than 50 ft-lb (68 J). However, C_vUSE values below these criteria may be acceptable if it is demonstrated, in a manner approved by the Director of the Office of Nuclear Reactor Regulation, that the lower values of C_vUSE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of C_vUSE values and describes two methods for determining C_vUSE values for RV beltline materials, depending on whether a given RV beltline material is represented in the plant's Reactor Vessel Material Surveillance Program (i.e., 10 CFR Part 50, Appendix H program).

4.2.1.1 Summary of Technical Information in the Application

Section 4.2.1 of the application addressed the requirement that RV beltline materials must maintain a C_vUSE value of not less than 50 ft-lbs throughout the life of the vessel, unless it is demonstrated, in a manner approved by the Director of the Office of Nuclear Reactor Regulation, that lower values of C_vUSE will provide margins of safety against fracture that are equivalent to those required by Appendix G of Section XI of the ASME Code. The applicant stated that the C_vUSE values have been calculated through the period of extended operation, using guidance from Regulatory Guide 1.99, Revision 2. A value of 54 EFPY was used as the end-of-life criterion for the RV. The application contains the information derived from the

C_vUSE analysis. It includes a list of all beltline materials, the weight percent copper in the steel, the end-of-life fluence for the RV located one-quarter from the vessel's inside surface (i.e., 1/4T thickness of the vessel), and the initial and final C_vUSE values. The applicant concludes that the end-of-life C_vUSE results are above the screening criterion of 50 ft-lb (68 J). The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.1.2 Staff Evaluation

The applicant summarized the end-of-extended operating period USE analyses for the Units 1 and 2 RV beltline materials in Tables 4.2-1 and 4.2-2, respectively, of the LRA. Since all of the C_vUSE values are above the 50 ft-lb (68 J) screening criterion, the staff finds that, with respect to C_vUSE, the Florida Power and Light Company (FPL) RVs have sufficient margin to perform their intended function through the end of the period of extended operation.

The staff performed an independent calculation of the end-of-extended life C_vUSE values for the beltline materials used to fabricate the St. Lucie RVs. For those RV beltline materials that were not represented in the applicant's RV material surveillance program, the staff applied Regulatory Position 1.2 of Regulatory Guide 1.99, Revision 2, to estimate the percent loss of C_vUSE as a function of copper content and neutron fluence for the beltline materials, as evaluated using the 54 EFPY end-of-extended life fluence. For RV materials represented in the applicant's RV material surveillance program, the staff applied Regulatory Position 2.2 as its bases for estimating the percentage drop in C_vUSE.

In regard to the staff's independent USE analysis for the St. Lucie Units 1 and 2 beltline materials, the staff confirmed the most limiting beltline materials identified by the staff for the St. Lucie Units 1 and 2 RVs were the same as those identified by the applicant for the RVs. Although the staff's calculated USE values for the limiting RV beltline materials were not always consistent with the applicant's calculated USE values, both the staff's and the applicant's USE analyses confirmed that the USE values for the St. Lucie beltline materials will remain at or above the 50 ft-lb acceptance criteria of 10 CFR Part 50 Appendix G through the expirations of the extended periods of operation for the units.

The staff determined that the 60-year USE assessment for the RV beltline materials is bounded (limited) by the USE value for the intermediate shell plate C-7-2 and lower shell plate M-4116-1 for St. Lucie Units 1 and 2, respectively. The staff calculated the projected USE values for these materials to be 57 ft-lb and 71 ft-lb, for St. Lucie Units 1 and 2, respectively, through the expiration of the extended period of operation for the unit. These materials meet the staff's end-of-life 50 ft-lb acceptance criterion for USE. Based on the staff's independent USE calculations for St. Lucie Units 1 and 2, the staff concludes that the RV beltline materials will have adequate USE through the expiration of the extended period of operation for the unit.

The staff confirmed that all RV beltline materials will continue to satisfy the C_vUSE value requirements of 10 CFR Part 50, Appendix G, through the end-of-extended operating lives for the St. Lucie reactor units. The staff, therefore, concludes that the applicant's TLAA for calculating the C_vUSE values of the RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have adequate USE levels and fracture toughness through the end-of-extended period of operation.

4.2.2 Pressurized Thermal Shock

Section 50.61 of 10 CFR Part 50 provides the fracture toughness requirements protecting the RVs of pressurized-water reactors (PWRs) against the consequences of PTS. Licensees are required to perform an assessment of the RV materials' projected values of the PTS reference temperature, RT_{PTS}, through the end of their operating license. If approved for license renewal, this would include TLAAs for PTS up through the end-of-extended operating terms for the St. Lucie units. Upon approval of its application for a period of extended operation for St. Lucie Units 1 and 2, this period would be 54 EFPY. The rule requires each licensee to calculate the end-of-life RT_{PTS} value for each material located within the beltline of the reactor pressure vessel. The RT_{PTS} value for each beltline material is the sum of the unirradiated nil-ductility reference temperature (RT_{NDT}) value, a shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation of the material (i.e., @ RT_{NDT} value), and an additional margin value to account for uncertainties (i.e., M value). Section 50.61 of 10 CFR Part 50 also provides screening criteria against which the calculated RT_{PTS} values are to be evaluated. For RV beltline base metal materials (forging or plate materials) and longitudinal (axial) weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 270 °F. For RV beltline circumferential weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300 °F. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of RT_{PTS} values and describes two methods for determining RT_{PTS} for RV materials, depending on whether a given RV beltline material is represented in the plant's RV material surveillance program (i.e., 10 CFR Part 50, Appendix H program).

4.2.2.1 Summary of Technical Information in the Application

Section 4.2.2 of the LRA addresses the 10 CFR 50.61 requirement that the RV be protected against PTS. The applicant states that the screening criteria in 10 CFR 50.61 are 270 °F for plates, forgings, and axial welds and 300 °F for circumferential welds. According to the regulation, if the calculated RT_{PTS} values for the beltline materials are less than the screening criteria, then the RV is acceptable with respect to risk of failure during postulated thermal shock transients. In this part of the application, the applicant describes the projected values of RT_{PTS} over the period of extended operation (54 EFPY) to demonstrate that the screening criteria are not violated. The applicant states that this analysis has been carried out and that the results do not exceed the screening criteria. The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.2.2 Staff Evaluation

The applicant provided its end-of-extended operating PTS assessments for the Units 1 and 2 beltline RV materials in Tables 4.2-3 and 4.2-4, respectively, of the LRA. The staff performed an independent calculation of the RT_{PTS} values for the Units 1 and 2 beltline RV materials, based on the projected end-of-extended operating term (54 EFPY) neutron fluences for the materials. In reviewing the applicant's description of the PTS analysis, the staff examined the data and results of the analysis, as summarized in Tables 4.2-3 and 4.2-4 of the LRA. The staff's calculated RT_{PTS} values for the RV beltline materials were within 2 degrees of the applicant's calculated RT_{PTS} values. Both the staff's and the applicant's PTS analyses confirm that the RT_{PTS} values for the St. Lucie Units 1 and 2 beltline materials will remain under the PTS screening criteria of 10 CFR 50.61 through the period of extended operating periods for the units.

For the Unit 1 RV, the staff determined that the lower shell axial welds 3-203 A, B, and C are the most limiting materials and calculated the end-of-extended-operating-term RT_{PTS} value for these materials to be 240 °F. For the St. Lucie Unit 2 RV, the staff determined that intermediate shell plate M-605-2 is the most limiting material and calculated the end-of-extended operating term RT_{PTS} value for this material to be 174 °F. All of these materials meet the 10 CFR 50.61 screening criteria for longitudinal weld and base metal materials of 270 °F. Based on these considerations, the staff finds the applicant's TLAAs for protecting the Units 1 and 2 vessels against PTS to be acceptable because the staff confirmed that the RT_{PTS} values for all Units 1 and 2 RV beltline materials remain below the screening criteria of 10 CFR 50.61. The staff therefore concludes that the applicant's TLAA for calculating the RT_{PTS} values for the Units 1 and 2 RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have sufficient protection against PTS events through the end-of-period of extended operations.

4.2.3 Pressure-Temperature Limits

The requirements in 10 CFR Part 50, Appendix G, are designed to protect the integrity of the reactor coolant pressure boundary in nuclear power plants. The staff evaluates the P-T limit curves based on NRC regulations and guidance. Appendix G to 10 CFR Part 50 requires that P-T limit curves be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code. Appendix G to 10 CFR Part 50 also provides minimum temperature requirements that must be considered in the development of the P-T limit curves. SRP Section 5.3.2 provides an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RV based on the linear elastic fracture mechanics methodology of Appendix G to Section XI of the ASME Code. The critical locations in the RV beltline region for calculating heatup and cooldown P-T curves are the 1/4 thickness (1/4T) and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.

Operation of the reactor cooling system (RCS) is also limited by the net positive suction curves for the RCPs. These curves specify the minimum pressure required to operate the RCPs. Therefore, in order to heat up and cool down, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G P-T limits and the net positive suction curves of the RCPs.

4.2.3.1 Summary of Technical Information in the Application

In Section 4.2.3 of the LRA, the applicant addresses the requirement in 10 CFR Part 50, Appendix G, that normal operations—including heatup, cooldown, and transient operating conditions—and pressure-test operations of the RV be accomplished within established P-T limits. These limits are established by calculations that utilize the materials and fluence data obtained through the unit-specific reactor surveillance capsule program.

4.2.3.2 Staff Evaluation

The P-T limits are established by calculations that utilize the materials and fluence data obtained through the unit-specific reactor surveillance capsule program.

Normally, the P-T limits are calculated for several years into the future and remain valid for an established period of time, not to exceed the current operating license expiration. The current P-T limit curves for St. Lucie Unit 1 are acceptable through 23.6 EFPY of power operation. The current P-T limit curves for St. Lucie Unit 2 are acceptable though 21.7 EFPY of power operation. Part 50.90 of 10 CFR Part 50 requires licensees to submit new P-T limit curves for operating reactors for review and have the curves approved and implemented into the TS for the reactor units prior to the expiration of the most current P-T limits curves approved in the TS. The applicant will be required to submit the extended-period-of-operation P-T limit curves for the Units 1 and 2 RVs, and have the curves approved against the criteria of 10 CFR Part 50, Appendix G, and implemented into the TS prior to operation of the reactors during the extended operating terms for the units.

The staff will evaluate the extended-period-of-operation P-T limit curves for the Units 1 and 2 RVs prior to expiration of the current-operating-term P-T limit curves for the units. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operation of the units will be done in a manner that ensures the integrity of the RCS during the period of extended operations.

4.2.4 UFSAR Supplement

The applicant's UFSAR supplement for the TLAA on RV neutron embrittlement is provided in Section 18.3.1 of Appendices A1 and A2 for Units 1 and 2, respectively. The applicant's appropriate consideration of RV neutron embrittlement, including the effects of neutron irradiation on the PTS, USE, and P-T limit assessments for Units 1 and 2, constitutes the bases for the staff acceptance of the licensee's evaluation of the TLAA for the period of extended operation. On the basis of its review of the updated UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address RV neutron embrittlement on the Units 1 and 2 RV beltline materials for the period of extended operation is adequate.

4.2.5 Conclusions

The staff has reviewed the TLAAs regarding the maintenance of acceptable Charpy USE levels for the Units 1 and 2 RV materials and the ability of the Units 1 and 2 RVs to resist failure during postulated PTS events. On the basis of this evaluation, the staff concludes that the applicant's TLAAs for Charpy USE and PTS meet the respective requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 for the RV beltline materials as evaluated to the end-of-extended-operating periods for the units, and therefore satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for 60 years of operation.

Prior to operation of the reactors during the extended period of operation, the applicant will submit the end-of-extended-operating term P-T limit curves for the reactor units. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operation of the RCS for the units will be done in a manner that ensures the integrity of the RCS for the period of extended operation and that the curves will satisfy the requirements of 10 CFR Part 54.21(c)(1) for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the RV neutron embrittlement TLAA evaluation for the period of extended operation.

4.3 Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity due to metal fatigue, initiating and propagating cracks in the material. The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for plant mechanical components in St. Lucie Units 1 and 2 and, consequently, fatigue is part of the CLB for these components. The applicant addresses the TLAA evaluations performed to address thermal and mechanical fatigue analyses of plant mechanical components in Section 4.3 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has evaluated the TLAA in accordance with the requirements of 10 CFR 54.21(c)(1).

4.3.1 Summary of Technical Information in the Application

In Section 4.3.1 of the LRA, the applicant discussed the design requirements for components of the RCS at Units 1 and 2. The RVs, RV internals, pressurizers, SGs, RCPs, and the Unit 2 reactor coolant piping were designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The Unit 1 reactor coolant piping was designed in accordance with the requirements of ANSI B31.7, "Nuclear Power Piping." The applicant reanalyzed the Units 1 and 2 pressurizer surge lines in accordance with the requirements in Section III of the ASME Code in response to NRC Bulletin (BL) 88-11, "Pressurizer Surge Line Thermal Stratification." The applicant determined the fatigue usage factors for critical locations in the Units 1 and 2 Class 1 components using design cycles that were intended to be conservative and bounding for all foreseeable plant operations. The applicant noted that a review of Units 1 and 2 operating history indicates that the number cycles used in the design of these components bounds the number anticipated for the period of extended operation and, therefore, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant referenced the St. Lucie fatigue monitoring program (FMP) as a confirmatory program that assures that the design cycle limits are not exceeded during the period of extended operation. The FMP is described in Appendix B of the LRA.

In Section 4.3.2 of the LRA, the applicant discussed the design of ASME Class 2 and 3 components and ANSI B31.1 components. The requirements of these codes specify a stress reduction factor to be applied to the allowable thermal bending stress range if the number of full range cycles exceeds 7000. The applicant indicated that most piping systems within the scope of license renewal are only subject to occasional cyclic operation, and, consequently, the analyses will remain valid during the period of extended operation. However, the applicant did indicate that the RCS hot leg sample could exceed the 7000 cyclic limit during the period of extended operation, and that a further evaluation considering the projected number of cycles found that the analyses would be acceptable for the period of extended operation.

In Section 4.3.4 of the LRA, the applicant described the actions taken to address the issue of environmentally assisted fatigue. The applicant describes its evaluation of the following fatigue sensitive component locations.

- RV shell and lower head
- RV inlet and outlet nozzles
- pressurizer surge line

- RCS piping charging nozzle
- RCS piping safety injection nozzle
- shutdown cooling system Class 1 piping

The applicant discussed its proposed aging management program (AMP) to address pressurizer surge line fatigue at Units 1 and 2 during the period of extended operation. The applicant indicated that potential fatigue crack initiation and growth will be adequately managed during the period of extended operation by continued performance of the St. Lucie Inservice Inspection Program. The applicant indicated that several pressurizer surge line welds on both units have been examined ultrasonically with no reportable indications identified. The applicant indicated that additional inspections of the surge line welds will be performed prior to the period of extended operation, and that the results of these inspections will be used to determine the appropriate approach for addressing environmentally assisted fatigue of the surge lines.

4.3.2 Staff Evaluation

As discussed in the previous section, components of the Units 1 and 2 RCSs were designed to either the Class 1 requirements of the ASME Code or ANSI B31.7. The Class 1 requirements of both codes contain explicit criteria for the fatigue analysis of components. Consequently, the applicant identified the fatigue analysis of these components as TLAAs. The staff reviewed the applicant's evaluation of the Class 1 RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion requires that the CUF not exceed 1.0. The applicant noted that review of the St. Lucie plant operating history indicates that the number of cycles and severity of the transients assumed in the design of these components envelops the expected transients during the period of extended operation. In RAI 4.3-1, the staff requested that the applicant provide the following data.

- the current number of operating cycles and a description of the method used to determine the number and severity of the design transient from the plant operating history

- 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

- a comparison of the design transients listed in the UFSAR with the transients monitored by the FMP as described in Section B3.2.7 of the LRA, identifying any transients listed in the UFSAR that are not monitored by the FMP and explaining why it is not necessary to monitor these transients.

The applicant's October 10, 2002, response indicated that cycle counting has been performed since the startup of each unit. The applicant listed the UFSAR design transients for each unit in Tables 4.3-1.1 and 4.3-1.2 of the response. The applicant indicated that the design calculations were reviewed, and that design transients that result in a fatigue usage greater than 0.1 are monitored by the FMP. The applicant also indicated that transients associated with plant loading and unloading events were not monitored because Units 1 and 2 are not load-following plants and, therefore, the number of cycles used in the design is very conservative. The applicant's statement regarding the conservative number of design transients associated with plant loading and unloading events is consistent with the information presented in NUREG/CR-6260 for an older-vintage Combustion Engineering plant. The applicant provided comparisons of the number of design cycles with the number of transients projected for 60 years of plant operation at the monitored locations for each unit in Tables 4.3-1.3 and 4.3-1.4 of the response. The staff finds the applicant's criteria for selecting transients to be monitored by the FMP to be reasonable.

NRC BL 88-11, "Pressurizer Surge Line Thermal Stratification," identified a concern regarding the potential temperature stratification and thermal striping in the pressurizer surge line. The applicant indicated that the pressurizer surge lines were analyzed in response to the bulletin. NRC BL 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," identified a concern regarding the potential for temperature stratification or temperature oscillations in unisolable sections of piping attached to the RCS. In RAI 4.3-2, the staff requested the applicant to describe the actions taken to address NRC BL 88-08 during the period of extended operation. The applicant's October 10, 2002, response indicated that no fatigue calculations had been performed to address NRC BL 88-08. Therefore, no additional actions are required to address this bulletin during the period of extended operation.

The applicant indicated that the SGs, pressurizers, RVs, RCPs, control rod drive mechanisms, and all RCS piping have been evaluated and the results of the analyses have been determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The applicant's FMP tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components stay within their design basis. Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999, concluding.

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI [Nuclear Energy Institute] and EPRI [Electric Power Research Institute]), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40- to 60-year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant evaluated the component locations listed in NUREG/CR-6260, that are applicable to an older-vintage Combustion Engineering plant, for effect of the environment on the fatigue life of the components. The applicant also indicated 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. In RAI 4.3-3, the staff requested that the applicant provide the results of the usage factor evaluation for each of the six component locations listed in NUREG/CR-6260.

The applicant's October 10, 2002, response provides the St. Lucie Units 1 and 2 plant-specific usage factors that include environmental effects for the six components listed in NUREG/CR-6260 in Tables 4.3-3.1 and 4.3-3.2. The applicant calculated an environmental multiplier for the six components and applied that multiplier to the design CUF to obtain a CUF that accounts for environmental effects. The applicant's evaluation indicates that the CUFs, including environmental effects, are expected to be below the ASME Code limit of 1.0 at all locations except for the surge lines at both units for 60 years of plant operation.

The staff compared the results of the applicant's evaluation with the results presented in NUREG/CR-6260 for an older-vintage Combustion Engineering plant. NUREG/CR-6260 identified three locations where the CUF, including environmental effects, may be exceeded based on the number of design transient cycles. These locations include the surge line, the charging nozzle, and the safety injection nozzle. The applicant indicated that the charging and safety injection nozzles at Units 1 and 2 are carbon steel as opposed to the stainless steel listed for the charging and safety injection nozzles in NUREG/CR-6260. The environmental multiplier for carbon steel is less than the environmental multiplier for stainless steel in a low oxygen (PWR) environment. Application of carbon steel environmental multipliers for the NUREG/CR-6260 charging and safety injection nozzles would result in CUFs less than 1.0. In its November 27, 2002, supplemental response, the applicant indicated that the location of highest fatigue usage on the Unit 2 charging nozzle occurs at the piping side of the safe end, which is stainless steel. The applicant's evaluation of this location, using the appropriate stainless steel environmental multiplier, indicates the safe end CUF is expected to be less than 1.0 for 60 years of plant operation. This would leave the pressurizer surge line as the only location where the CUF, including environmental effects, exceeds 1.0. On the basis of the comparison of the results of the applicant's evaluation with the results presented in NUREG/CR-6260, the staff concludes that the results of the applicant's evaluation are reasonable.

The applicant indicates that the pressurizer surge line elbows required further evaluation for environmental fatigue during the period of extended operation. The applicant further indicated that it would use an AMP to address fatigue of the surge line during the period of extended operation. The AMP would rely on the Inservice Inspection Program to manage surge line fatigue during the period of extended operation. The applicant noted that no indications have been identified as a result of the weld examinations performed to date. The applicant also indicated that additional surge line weld examinations will be performed prior to the period of extended operation. The applicant indicated that the results of the examinations would be used to develop the approach for addressing environmentally assisted fatigue of the surge lines prior to the period of extended operation. This approach could include one or more of the following.

- further refinement of the fatigue analysis to lower the CUF(s) to below 1.0
- repair of the affected locations
- replacement of the affected locations
- management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC)

The applicant indicated that if the last option is selected, the inspection details, including scope, qualification, method, and frequency, will be provided to the NRC for review prior to the period of extended operation. The staff finds that the applicant's proposed options provide acceptable plant-specific approaches to address environmentally assisted fatigue of the St. Lucie Units 1 and 2 pressurizer surge lines during the period of extended operation in accordance with 10 CFR 54.21(c)(1). However, in accordance with 10 CFR 54.21(d), these options need to be included in the UFSAR supplement. This was designated Confirmatory Item 4.3.1-1.

By letter dated March 28, 2003, the applicant provided the updated UFSAR supplements for St. Lucie Units 1 and 2. The UFSAR supplements describe the applicant's proposed options to address environmentally assisted fatigue of the St. Lucie Units 1 and 2 pressurizer surge lines during the period of extended operation. The staff considers Confirmatory Item 4.3.1-1 to be closed.

ANSI B31.1 requires that a reduction factor be applied to the allowable bending stress range if the number of full range thermal cycles exceeds 7000. The applicant indicates that its review of plant operating practices found that most B31.1 systems in the scope of license renewal are subject to continuous steady-state operation, and the temperature only varies as a result of plant heatup and cooldown during plant transients, or for periodic testing. Therefore, the applicant concluded that the analyses of these piping components remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). However, the applicant indicated that the reactor coolant hot leg sample lines on both units could be subject to greater than 7,000 cycles during the period of extended operation. The applicant indicated that the sample piping and tubing were reevaluated for the number of expected cycles and found acceptable for the period of extended operation. Therefore, the applicant concluded that these analyses have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The staff finds the applicant's evaluation acceptable.

4.3.3 UFSAR Supplement

The applicant's Units 1 and 2 UFSAR supplements for metal fatigue are provided in Appendices A1 and A2 of the LRA, respectively. Section 18.2.7 of the Unit 1 supplement and Section 18.2.6 of the Unit 2 supplement describe the FMP. Section 18.3.2 of both UFSAR supplements describes the applicant's TLAA for metal fatigue. As discussed above, the applicant provided UFSAR supplements to describe the proposed options to address environmentally assisted fatigue of the St. Lucie Units 1 and 2 pressurizer surge lines during the period of extended operation. On the basis of its review of the UFSAR supplements for St. Lucie Units 1 and 2, the staff concludes that the UFSAR supplements contain a summary description of the TLAA, as required by 10 CFR 54.21(d).

4.3.4 Conclusions

On the basis of its evaluations of Units 1 and 2 components, the applicant concludes that the fatigue analysis of RCS components and piping remain valid for the period of extended operation. The applicant also has a FMP that maintains a record of the transients used in the fatigue analyses of RCS components. That process will continue during the period of extended operation.

The staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that for the metal fatigue TLAA, the analysis remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the metal fatigue TLAA evaluation for the period of extended operation.

4.4 Environmental Qualification

The aging (or qualified life) analysis for electrical/instrumentation and controls (I&C) components included as part of the environmental qualification (EQ) program (required by 10 CFR 50.49) that involve time-limited assumptions (as defined by the current operating term for the St. Lucie plant, i.e., 40 years) meet the 10 CFR 54.3 definition for TLAAs and are thus considered TLAAs for license renewal. The existing thermal, radiation, and wear cycle aging analyses required by 10 CFR 50.49 for plant electrical/I&C components identified as TLAAs have been evaluated by the applicant pursuant to 10 CFR 54.21(c)(1)(ii) to determine if they can be projected to the end of the period of extended operation by re-analysis or additional analysis.

The staff reviewed Section 4.4, "Environmental Qualification of Electric Equipment" of the LRA to determine whether there continues to be reasonable assurance that electrical/I&C components (after re-analysis for a 60-year qualified life) will be capable of performing their required safety function pursuant with 10 CFR 54.21(c)(1)(ii).

4.4.1 Summary of Technical Information in the Application

In Section 4.4 of the LRA, the applicant describes its process (which is encompassed as part of the existing 10 CFR 50.49 EQ program) for analysis (and also for re-analysis) of electrical/I&C component's qualified life. In addition, the applicant provides the results of its re-analysis to project the current 40-year qualified life to 60 years.

The applicant describes its process for re-analysis of qualified life of electrical/I&C components using the environmental service conditions that are applicable to the components. The environmental service conditions are divided into normal and accident service conditions. 10 CFR 50.49 requires that all significant aging effects from normal service conditions be considered as part of the qualified life analysis. Significant aging effects include the expected thermal aging effects from normal temperature exposure, any radiation effects during normal plant operation, and mechanical cycle effects as applicable. 10 CFR 50.49 also requires evaluation of the effects of any harsh environments the electrical/I&C components could be exposed to under accident conditions.

The description provided by the applicant of its re-analysis of qualified life based on normal service conditions for 60 years is as follows.

- Thermal-Aging Considerations—The specific analyses for thermal aging have been reviewed by the applicant to confirm that the existing qualified life calculations remain valid for the extended period of operation or a re-calculation projects the component's qualified life to encompass the extended period of operation.

- Radiation-Aging Considerations—The St. Lucie EQ Program has established bounding radiation dose qualification values for all EQ components. These bounding radiation dose values were determined through testing. To verify that these bounding radiation test values are acceptable for the period of extended operation, the total integrated dose values for the 60 year period were determined and then compared to these bounding radiation test values. The total integrated dose for the 60-year period is determined by adding 60-year normal operating dose (i.e., 1.5 times the 40-year normal operating dose) to the established accident dose for the component.

- Mechanical-Cycle Aging Considerations—The expected wear cycles to which electromechanical components will be subject to over a 60-year period were found (with margin) to be less than the wear cycles to which components were subjected to prior to the performance of design basis accident testing.

In summary, the applicant credits the EQ program as part of the screening process for ensuring that the qualified life of electrical/I&C components within the scope of 10 CFR 50.49 is maintained. The EQ program establishes the aging limit (qualified life) for each installed environmentally qualified component. The EQ program qualified life analysis is considered to be a TLAA for St. Lucie Units 1 and 2. Pursuant to 10 CFR 54.21(c)(1)(ii), a re-analyses was performed to demonstrate that the qualified life for electrical/I&C components has been projected to 60 years (i.e., the end of the period of extended operation). This re-analysis demonstrates that there is reasonable assurance that electrical/I&C components will be capable of performing their required safety function for 60 years, and thus for the period of extended operation.

4.4.2 Staff Evaluation

4.4.2.1 Radiation Aging

As part of the original type test for components to demonstrate their EQ for 40 years of operation, conservative (or bounding) radiation test values were selected (consistent with industry practice) to encompass the possibility for higher than normally expected radiation dose values if they were to occur due to plant modifications and events. Conservative radiation test values provide, if needed, the option for re-analysis (versus equipment replacement) to demonstrate continued EQ in accordance with the requirements of 10 CFR 50.49(e)(4). 10 CFR 50.49(e)(4) requires that the radiation environment be based on the type of radiation, the total dose expected during normal operation over the installed life of the equipment, and the radiation environment associated with the most severe design basis accident during or following which the equipment is required to remain functional, including the radiation resulting from recirculating fluids for equipment located near the recirculating lines and including dose-rate effects.

To extend EQ from 40 to 60 years, the conservative (or bounding) radiation test values (included as part of the original type test of components to demonstrate their EQ) were utilized. To verify that the original radiation test values are acceptable for the period of extended operation, the total integrated dose values for the 60 year period were determined and then compared to the original radiation test values. The total integrated dose for the 60-year period is determined by adding 60-year normal operating dose (i.e., 1.5 times the 40-year normal operating dose) to the established accident dose for the component.

At St. Lucie, to establish the normal operating dose, the maximum operating value for radiation was used as part of an EQ re-analysis for establishing a 60-year qualified life. The maximum operating value is based on an area radiation dose rate values for continuous operation assuming 1 percent failed fuel. The total integrated dose is determined by adding the 60-year normal operating dose to the appropriate accident dose for the specific location of the component. If the new total integrated dose for the 60 year period is less than the original radiation test values, components are considered acceptably qualified for 60 years (i.e., the extended period for license renewal).

The expected radiation dose to which components will be exposed over a 60-year period, plus the accident radiation dose (i.e., the new total integrated radiation dose), was found (with margin) to be less than the radiation dose to which components were exposed prior to design basis accident testing. Thus, there continues to be reasonable confidence that components will be capable of performing their required safety function if needed for 60 years. The staff concluded that the radiation aging for extending qualified life of components is acceptable, since it meets the requirements of 10 CFR 54.22(c)(ii).

4.4.2.2 Temperature Aging

As part of the original type test for components to demonstrate their EQ for 40 years of operation, conservative temperature test values were selected (consistent with industry practice) to represent normal operating temperatures. Conservative temperature test values provide, if needed, the option for re-analysis based on the Arrhenius method (versus equipment replacement) to demonstrate continued EQ in accordance with the requirements of 10 CFR 50.49(e)(5). 10 CFR 50.49(e)(5) requires that components qualified by test must be preconditioned by natural or artificial (accelerated) aging to their end-of-installed life condition. To meet this requirement, re-analysis must show that when the conservatism included to account for normal operating temperatures is reduced or eliminated, the component can be shown to have been aged (i.e., preconditioned by artificial (accelerated) aging to its end-of-life condition) to the equivalent of 60 years.

In Section 4.4 of the LRA, the applicant indicates that EQ acceptance criteria for temperature aging is the component's maximum required operating temperature. If the maximum operating temperature is equal to or less than the temperature to which the component was qualified by test, the component is considered qualified.

Each component's qualification temperature used for aging to a qualified life of 40 years was re-calculated for 60 years using the Arrhenius method. The St. Lucie Units 1 and 2 Technical Specifications temperature limit for inside each unit's containment is 120 °F. By plant procedure, the temperature is limited to 115 °F on both units. Normally the 120 °F temperature is used for the in-containment aging calculations, however, the plant procedures limit of 115 °F is used for some components in Unit 2. Because the aging calculation for Unit 1 assumes a continuous temperature of 120 °F (which exceeds the component's maximum required operating temperature of 115 °F by 5 °F), takes into account the component's self heating, and does not credit seasonal and shutdown temperature reductions, significant margin exists to ensure that the qualified life of EQ components inside containment is not exceeded. For components in Unit 2 where the 115 °F temperature is used as the qualification temperature, significant margin also exists to ensure that the qualified life of EQ components inside containment is not exceeded. Significant margin exists because (1) the aging calculation assumes a continuous temperature of 115 °F (which is equal to the component's maximum required operating temperature), (2) components are located in containment at an elevation that is lower than the temperature detectors used to establish the 115 °F operating limit and thus components will be subject to an actual temperature that is less than 115 °F, and (3) the aging calculation takes into account the component's self heating and does not credit seasonal and shutdown temperature reductions. For areas outside containment, the aging calculations are based on a temperature of 104 °F. Because the aging calculation assumes a continuous temperature of 104 °F, which is significantly higher than the average temperatures that would normally be expected to exist outside containment, significant margin exists to ensure that the qualified life of EQ components outside containment is not exceeded. In addition, no change of a component's activation energy (determined and utilized as part of the original aging calculation for 40 years) was used in the re-calculation for 60 years.

For those circumstances in which a component's maximum required operating temperature is equal to the temperature to which it had been tested to demonstrate EQ, the staff was concerned that there may be no margin to account for the uncertainties of the Arrhenius method. The applicant, by letter dated October 10, 2002 (in response to a July 1, 2002 request for additional information), indicated the following—The maximum operating temperatures referred to in the LRA are the 104 °F design ambient for outside the Containments, and the 120 °F design ambient (Unit 1) and 115 °F design ambient (Unit 2) inside the Containments used to calculate the qualified life of EQ components. Section 4.4 also indicates that EQ components are assumed to be exposed to continuous design ambient temperatures (104 °F, 120 °F, or 115 °F, as appropriate), and that the evaluation does not credit lower temperatures due to seasonal/daily temperature changes or temperature changes associated with unit shutdown. These seasonal and shutdown reductions in temperature are more than adequate to account for the uncertainties of the Arrhenius methodology when considering that the EQ components are exposed to higher continuous design ambient temperature conditions. As an additional conservatism, continuous self-heating is also added to the design ambient temperatures.

The staff agrees that the average operating temperature of components due to seasonal/daily temperature changes or temperature changes associated with unit shutdown over a 60-year period will be less than the maximum required operating temperature to which the Arrhenius method was applied. The difference between the average operating temperature and the maximum continuous design temperature to which components are qualified can therefore be considered sufficient to account for the uncertainties of the Arrhenius methodology. The applicant's EQ acceptance criteria for establishing temperature aging (i.e., if the maximum operating temperature is equal to or less than the temperature to which the component was qualified by test, the component is considered qualified) is therefore considered acceptable.

The expected temperature to which components will be exposed over a 60-year period was found (with margin) to be less than the equivalent temperature (determined by the Arrhenius methodology) to which components were exposed prior to design basis accident testing. In addition, no change of a component's activation energy (determined and utilized as part of the original aging calculation for 40 years as determined by the Arrhenius Methodology) was used in the re-calculation for 60 years. Thus, there continues to be reasonable assurance that components will be capable of performing their required safety function if needed for 60 years. The staff concludes that the temperature aging for extending qualified life of components is acceptable since it meets the requirements of 10 CFR 21(c)(ii).

4.4.2.3 Wear Cycle Aging

Wear cycle aging mechanically ages the electro-mechanical components to the end of their qualified lives prior to performing design basis accident testing. The EQ components at St. Lucie Units 1 and 2, where wear is a consideration, are motors and solenoid valves.

EQ motors are either normally energized or in a standby mode during normal operation. Standby components are tested once a month and with preventive maintenance every 18 months. This results in less than 2000 cycles for valve operators and less than 1000 cycles for other motors over a 60-year life. This is less than the 2000 cycles that was performed during valve operator EQ testing. The motors considered continuous duty in the EQ Program are the Units 1 and 2 containment fan cooler motors, the Units 1 and 2 charging pump motors, and certain Unit 2 ventilation fan motors. The qualification of the electro-mechanical components of these motors is maintained through a combination of maintenance required by the conditions in the test report (e.g., periodic replacement of seals that were only aged for ten years prior to qualification testing), and maintenance recommended by the vendor (e.g., overhaul a motor after 25,000 hours of operation or every 5 years, whichever comes first). The frequency of maintenance for these components is normally governed by the maintenance requirements of the vendor rather than by any restrictions that are required by the EQ test report.

Depending on the application, solenoid valves can be cycled significantly more often than motors. The solenoid valve vendors—ASCO, Target Rock, and Valcor—cycled their valves from 18,000 to 50,000 times during their EQ testing. Of these three solenoid valves used in EQ applications at St. Lucie, only ASCO solenoid valves are used in high cycle applications. ASCO solenoid valves that experience a high cycle rate are classified as normally energized. As identified in the EQ evaluations, normally energized solenoid valves reach the end of their thermal qualified lives prior to 40 years. Therefore, they will be replaced periodically when they reach the end of their qualified lives. Thus, their qualification for life cycles is not considered to be a TLAA. Normally, de-energized solenoid valves are operated the same as any other standby component, thereby establishing acceptability for 60 years.

The expected wear cycles to which electro-mechanical components will be subject to over a 60 year period was found (with margin) to be less than the wear cycles to which components were subjected prior to the performance of design basis accident testing. Thus, there continues to be reasonable assurance that electro-mechanical components will be capable of performing their required safety function for 60 years. The staff concluded that the wear cycle aging for extending qualified life of electro-mechanical components is acceptable since it meets the requirements in 10 CFR 54.21(c)(i).

4.4.3 UFSAR Supplements

The staff reviewed Section 18.3.3, "Environmental Qualification," of Appendix A1 and A2 to the St. Lucie Units 1 and 2 LRA and found descriptions of the above-described EQ program for electrical/I&C component TLAA evaluations. These UFSAR supplement descriptions provide a summary of the programs and activities for the evaluation of TLAA for electrical/I&C components, meet the requirements of 10 CFR 54.21(d), and are considered acceptable.

4.4.4 Conclusions

The staff has reviewed the information in Sections 4.4, 4.4.1, and 4.4.2 of the LRA. On the basis of this review, the staff concludes that the applicant (for electrical/I&C components that meet the definition for TLAA as defined in 10 CFR 54.3) has projected the TLAA (i.e., the 10 CFR 50.49 radiation, temperature, and wear cycle aging analyses) from the current 40 years to 60 years (i.e., to the end of the period of extended operation), as provided in 10 CFR 54.21(c)(1)(ii). In addition, the staff concludes that the UFSAR supplements contain a summary description of the programs and activities for the evaluation of TLAA as required by 10 CFR 54.21(d).

4.5 Metal Containment and Penetration Fatigue

4.5.1 Metal Containment Fatigue

4.5.1.1 Summary of Technical Information in the Application

The applicant states that no TLAAs exist for the St. Lucie Unit 1 and 2 containment vessels. These vessels are fabricated from welded steel plates. The criteria that are applied in the design of these vessels assure that the specified leak rate is not exceeded under the design basis accident conditions. The containment vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III. No fatigue analysis was required for these applicable design codes. The applicant concludes that fatigue of the Units 1 and 2 containment vessels are not TLAAs.

4.5.1.2 Staff Evaluation

In RAI 4.5-1, the staff requested that the applicant indicate how the design criteria for the containment penetrations provide assurance that the specified leak rate for the containment vessels will not be exceeded. In a letter dated October 10, 2002, the applicant states that the Unit 1 containment vessel was designed to meet the requirements of ASME Section III, 1968, Article 4, Subsection N-415, "Analysis for Cyclic Operation." The Unit 2 containment vessel was designed to meet the requirements of ASME Section III, Article 4, Subsection NB-3222.4, "Analysis for Cyclic Operation." These sections specify conditions for which analysis of cyclic service is not required. Meeting design requirements precludes cyclic fatigue cracking that may result in leakage. The applicant, therefore, did not perform fatigue analyses or TLAAs for these vessels. However, compliance with leakage design criteria is verified through periodic testing in accordance with ASME Section XI, Subsection IWE, "Inservice Inspection Program," as described in LRA Appendix B, Subsection 3.2.2.2. Compliance with the testing requirements assures containment integrity. Therefore, the staff finds the applicant's response acceptable.

4.5.2 Penetration Fatigue

4.5.2.1 Summary of Technical Information in the Application

The applicant states that the containment penetration bellows at Units 1 and 2 are specified to withstand a lifetime total of 7,000 cycles of expansion and compression as a result of maximum operating thermal expansion, and 200 cycles of seismic motion and differential settlement.

The containment penetrations are categorized into five types, depending on the operating conditions. The designs of penetration bellows, which must accommodate considerable or moderate thermal movements, are bounded by the thermal design limits of the associated piping systems. The other bellows do not require a thermal fatigue analysis because they are associated with cold penetrations, penetrations used for post-accident scenarios, or penetrations that are not subject to high temperatures. For these bellows, the applicant stated that the 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

The applicant states that the analyses associated with containment penetration bellows fatigue have been evaluated and determined to remain valid for the period of extended operation.

4.5.2.2 Staff Evaluation

The applicant stated that containment penetration bellows were specified to withstand a lifetime total of 7000 cycles of thermal expansion and compression, and 200 cycles due to other effects. In RAI 4.5-2, the staff requested that the applicant show that the specified cycles bound the period of extended operation.

In a letter dated October 10, 2002, responding to RAI 4.5-2, the applicant states that the piping systems associated with hot penetration bellows were evaluated in LRA Subsections 4.3.1 and 4.3.2 and found to be acceptable for the period of extended operation. The applicant also states that the methods used to confirm that the existing design cycles for Class 1 components are conservative and bounding for extended operation are described. Four St. Lucie Unit 1 containment penetrations associated with safety injection piping are designed to ASME Section III Class 1 requirements. The cycles that these piping components are subjected to are monitored as part of the FMP. Table 4.3-1.3 of the response to RAI 4.3-1 shows that the 7000 thermal expansion cycles bound the total number of thermal cycles assumed for the Class 1 safety injection piping during 60 years of operation.

The applicant states that the remainder of the Units 1 and 2 containment penetrations are associated with piping designed to ASME Section III, Class 2 requirements. In Subsection 4.3.2 of the LRA, the applicant indicates that these piping systems, as well as the containment penetrations associated with these piping systems, were originally designed for 7000 full temperature thermal cycles. The applicant performed an evaluation of these piping systems, reviewed plant operating procedures and practices, and concluded that these piping systems will not exceed 7000 equivalent full temperature thermal cycles during 60 years of operation. A review of plant operations to date also concluded that 200 cycles bound the expected number of seismic and differential settlement cycles that could occur during 60 years of operation. The staff finds this justification reasonable and acceptable because the current fatigue analyses limits will not be exceeded during the period of extended operation because the designed number of cycles will not be exceeded.

In RAI 4.5-2, the staff also requested that the applicant describe the methods used to provide assurance that hot penetration bellows will withstand the cycles specified in the LRA under the corresponding thermal expansion loads and other loads for the period of extended operation. In its response, the applicant stated that the methods used to provide assurance that the penetration bellows will withstand the specified cycles include the FMP. Additional information regarding the design of the penetration bellows was also provided in Appendix 3G of the Unit 1 UFSAR. This information is also applicable to Unit 2. The staff finds that the applicant's response is acceptable because the margin in the design of the containment penetration bellows, as compared to actual plant operations, will be maintained for the period of extended operation.

In RAI 4.5-3, the staff asked if the containment penetration bellows are included within the scope of the St. Lucie FMP, or to provide justification for the exclusion if they are not. In a letter dated November 27, 2002, responding to RAI 4.5-3, the applicant states that the scope of the FMP, as described in LRA Appendix B, comprises RCS Class 1 components. The only Class 1 piping containment penetrations and associated bellows at Units 1 and 2 that are required to accommodate thermal expansion are those associated with Unit 1 safety injection piping. These penetrations are included in the scope of the FMP. Penetrations such as those associated with the Class 1 hot leg sample lines are not required to accommodate thermal expansion and are therefore not included in the FMP.

The containment penetrations and associated bellows for Class 2 piping systems at Units 1 and 2 were originally designed to accommodate 7000 equivalent full thermal cycles. The applicant stated that these piping systems will not exceed 7000 full thermal cycles during 60 years of operation. On this basis, the applicant stated that there is no need to monitor the thermal cycles of these penetrations and, therefore, the penetrations associated with Class 2 piping systems are not included in the scope of the FMP. The staff finds the applicant's response acceptable because the applicant demonstrated that the margin in the design of the penetrations will be maintained for the period of extended operation.

4.5.3 UFSAR Supplement

The staff has reviewed the UFSAR supplement, Section 18.3.4, for each unit, which provides a description of the containment penetration TLAA. The staff finds the description of the containment penetration fatigue evaluation sufficient to satisfy the requirements of 10 CFR 54.21(d).

4.5.4 Conclusions

The staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for the metal containment and penetrations fatigue TLAA, the analyses remain valid and have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplements contain an appropriate summary description of the containment penetrations fatigue TLAA evaluation for the period of extended operation.

4.6 Plant-Specific Time-Limited Aging Analyses

In Section 4.6 of the LRA, the applicant provides its evaluation of St Lucie plant-specific TLAAs. The TLAAs evaluated include the following.

- leak-before-break for reactor coolant system piping
- crane load cycle limit
- *Unit 1 core support barrel repair*
- Alloy 600 instrument nozzle repairs

The staff reviewed the site-specific TLAAs to verify the applicant's evaluations meet the requirements contained in 10 CFR 54.21(c)(1).

4.6.1 Leak-Before-Break

4.6.1.1 Summary of Technical Information in the Application

The applicant describes its LBB analysis in Section 4.6.1 of the LRA. The staff reviewed this section to determine whether the applicant provided adequate information to meet the requirements contained in 10 CFR 54.21(c) related to the TLAA for LBB for Units 1 and 2.

A successful application of LBB to the RCS primary loop piping is described in CEN-367-A, "Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering

Designed Nuclear Steam Supply Systems." This report provides the technical basis for evaluating two distinct postulated flaws in the main RCS piping using the two essential elements of the LBB methodology—(1) the determination of the leakage flaw size under the normal loading condition, and (2) the determination of the allowable flaw size under the faulted loading condition.

The applicant states that there are two considerations for the LBB analysis. The first analysis consideration is that the material properties of the cast austenitic stainless steel can change over time. Cast austenitic stainless steels used in the RCS are subject to thermal aging during service. This thermal aging causes an elevation in the yield strength of the material and a degradation of the fracture toughness, the degree of degradation being a function of the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation or fully aged point is reached.

CEN-367-A used the fracture toughness values of the SA515 Grade 70 carbon steel weld in the LBB analysis, which are the lowest among all base and weld materials in the primary loop piping system. The staff compared the fracture toughness values in CEN-367-A with the more recent information in NUREG-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," and found that the CEN-367-A toughness data are more conservative than the NUREG-6177 lower-bound curve. Therefore, because the original analysis supporting LBB relied on fully aged stainless steel material properties, the analysis does not have a material property time dependency that requires further evaluation for license renewal.

The second analysis consideration is the accumulation of actual fatigue transient cycles over time that could invalidate the fatigue flaw growth analysis that was done as part of the original LBB analysis. A review of the accumulation of the applicable fatigue transient cycles is performed to meet the TLAA definition. This review was done within the scope of the FMP. The applicant stated that the continued implementation of the FMP provides reasonable assurance that thermal fatigue will be managed for the Class I components such that they will continue to perform their intended function(s) for the period of extended operation.

4.6.1.2 Staff Evaluation

In the LRA regarding LBB, the applicant intended to demonstrate through qualitative assessment that the plant-specific FMP is capable of programmatically managing the assumptions, including the fatigue cycles, in the existing LBB analyses for the period of extended operation. The staff confirmed that the LBB applications for the primary loop piping were approved generically for Combustion Engineering Owners Group (CEOG) plants by the NRC on October 30, 1990, and specifically for St. Lucie Units 1 and 2, on March 5, 1993. The LBB analyses, which provided technical bases for these approved LBB applications, considered the thermal aging of the cast austenitic stainless steel material of the piping and assumed 40 years of operation. Since the primary loop piping contains cast stainless steel material, the LBB application is a TLAA for both plants.

The thermal aging of the cast stainless steel material has been identified as an issue to be reevaluated. The applicant's reevaluation revealed that the original LBB analyses had employed the thermal aging properties, which are more conservative than the lower-bound curve documented in NUREG-6177, and therefore bounded the aging material data for St. Lucie. The staff performed a comparison of the material aging information in CEN-367-A with the information in NUREG-6177, and agreed with the applicant's conclusion that fully aged, lower bounding material property was used in the original LBB analyses. Hence, the properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the period of extended operation.

For the remaining primary loop piping materials, instead of revising the original analyses by taking into account the fatigue transient cycles for the period of extended operation, the applicant relies on the plant-specific FMP to ensure that the accumulation of the applicable fatigue transient cycles over time will not invalidate the fatigue flaw growth analysis that was performed as part of the original LBB analyses. With this program in place, which calls for constant review of the accumulation of applicable fatigue transient cycles, the applicant concluded that the continued implementation of the FMP will provide reasonable assurance that the RCS components within the scope of license renewal will continue to perform their intended functions consistent with the CLBs for the period of extended operation. The staff reviewed the FMP and determined that the program is adequate to monitor the applicable set of transients and their limits, and to count the actual thermal cycle transients to ensure that it is within the allowable limits of the defined transients. In the event design cycle limits are approached, the applicant will review the FMP and determine appropriate actions.

Based on the above evaluation, the staff agrees with the applicant's conclusion that the continued implementation of the FMP provides reasonable assurance that thermal fatigue will be managed for the primary loop piping and components, and that therefore the analyses for this TLAA remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

Since the V.C. Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff has considered the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds as an operating plant issue affecting all piping with or without approved LBB applications. To resolve this issue, the industry has taken the initiative to (1) develop overall inspection and evaluation guidance, (2) assess the current inspection technology, and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWRs while the industry completes the development of the final report. The staff accepted this interim report in an SE dated June 14, 2001, with the following statement, "Should the industry not be timely in resolving inspection capabilities to identify PWSCC in Alloy 600 welds, regulatory action may result." The final industry report on this issue has not yet been published, and the staff is resolving it under 10 CFR Part 50, pending receipt of this final report and additional ultrasonic testing inspection data from piping involving Alloy 182/82 weld material from the industry.

4.6.1.3 UFSAR Supplement

The applicant's UFSAR supplement for LBB for RCS piping is provided in Section 18.3.5 of Appendices A1 and A2 for Units 1 and 2, respectively. The plant design cycles used in the applicant's LBB analysis are consistent with those utilized in the fatigue crack growth analysis and bound the period of extended operation. In addition, the applicant's appropriate consideration of thermal aging of the cast austenitic stainless steel material constitutes the basis for the staff acceptance of the licensee's evaluation of the LBB TLAA for the period of extended operation. On the basis of its review of the UFSAR supplements, the staff concludes that the summary description of the applicant's actions to address LBB for the period of extended operation is adequate.

4.6.1.4 Conclusions

The staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that for LBB TLAA, the analyses remain valid and the effects of aging on the pressure boundary function will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplements contain an appropriate summary description of the containment penetrations fatigue TLAA evaluation for the period of extended operation.

4.6.2 Crane Load Cycle Limit

4.6.2.1 Summary of Technical Information in Application

In Section 4.6.2 of the LRA, the applicant identified the crane load cycle limit as a TLAA for the cranes within the scope of license renewal. The cranes include the reactor building polar cranes, refueling machine and hoist (Unit 2 only), reactor containment building auxiliary telescoping jib cranes, fuel transfer machine (Unit 2 only), spent fuel handling machine (Unit 2 only), refueling canal bulkhead monorail (Unit 2 only), cask storage pool bulkhead monorail (Unit 2 only) and intake structure bridge cranes. The applicant stated that these cranes are designed in accordance with the criteria of the Crane Manufacturers Association of America (CMAA) Specification No. 70, "Specifications for Electric Overhead Traveling Cranes," and are acceptable for at least 20,000 to 200,000 load cycles. The applicant also stated that these cranes are used primarily during refueling outages. Occasionally, cranes make lifts at or near their rated capacity. However, most crane lifts are substantially less than their rated capacity. The St. Lucie Unit 2 spent fuel handling machine is bounding for the other cranes within the renewal scope.

The applicant states that the spent fuel handling machine is used primarily to move fuel assemblies during refueling cycles and is subject to the most loading cycles at or near its rated capacity. Considering a 3-batch fuel management scheme, which assumes one-third of the core is replaced at each refueling (every 18 months), and a full core off load every 10 years, the number of lifts performed in 60 years is projected to be less than 7100. Since the spent fuel handling machine load cycle analysis bounds the other cranes within the license renewal scope, all the cranes considered in this evaluation are adequate for expected load cycles over the period of extended operation. In addition, because crane gearing and shafting fatigue design per CMAA-70 are related to load lifts, the crane gearing and shafting are also adequate for the period of extended operation. Therefore, the applicant concluded that the crane analyses associated with crane design, including fatigue, remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.6.2.2 Staff Evaluation

The staff reviewed Section 4.6.2 of the LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1). On the basis of the staff's review of the information described above, the staff finds the applicant's analysis demonstrated that the actual usage of the cranes over the projected life through the period of extended operation will be far less than the analyzed load cycles per the design specification, and all the cranes within the LRA will continue to perform their intended function throughout the period of extended operation. Therefore, the applicant's TLAA concerning the crane load cycle limit meets the requirements of 10 CFR 54.21(c)(1).

4.6.2.3 UFSAR Supplement

The applicant provides a summary description of the evaluation of the crane load cycle limit in Section 18.3.6 of Appendix A1 and Section 18.3.6 of Appendix A2, for Units 1 and 2, respectively. The applicant stated that the load cycles for these cranes were evaluated for the period of extended operation. On the basis of the staff's review, the staff concludes that the applicant's description is sufficient to satisfy the requirements of 10 CFR 54.21(d).

4.6.2.4 Conclusions

The staff concludes that the applicant has provided an acceptable demonstration pursuant to 10 CFR 54.21(c)(1) that, for the crane load cycle limits TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplements contain an appropriate summary description of this TLAA evaluation for the period of extended operation.

4.6.3 Unit 1 Core Support Barrel Repair

4.6.3.1 Summary of Technical Information in the Application

In Section 4.6.3 of the LRA, the applicant states that during the 1983 St. Lucie Unit 1 refueling outage, the CSB and thermal shield assembly were observed to be damaged. The thermal shield was permanently removed. Four lugs were found to have separated from the CSB, and through-wall cracks were found adjacent to the lug areas. The CSB was repaired at the thermal shield support lug locations. Through-wall cracks were arrested with crack-arrestor holes and non-through-wall cracks were machined out. The lug tear-out areas were machined out and patched. The crack arrestor holes were sealed by inserting expandable plugs. The nuclear steam supply system supplier performed an analysis of the CSB repair method that demonstrated that the repair patches and expandable plug designs were acceptable for the remaining (40-year) life of the plant, consistent with ASME Code allowable stresses.

In 1984, a post-repair inspection of the CSB lug area repairs was performed to verify proper installation of the plugs and to provide a baseline for comparison of data from subsequent inspections. A visual and mechanical inspection was performed in 1986, after one cycle of operation. The inspection report concluded that no changes had occurred with respect to the baseline inspection. The applicant determined that the CSB was acceptable for long-term operation, and only visual inspections at 10-year intervals were necessary. A 10-year inservice visual inspection of the lug repair areas was performed during the 1996 refueling outage. On the basis of comparisons between the 1984 and 1986 inspection results, no abnormal changes were observed in the repaired lug areas.

The analyses and followup inspection reports for the repaired CSB and the expandable plugs were screened against the six TLAA criteria. The applicant determined that two specific elements of the repair qualify as TLAAs—(1) the fatigue analysis of the CSB middle cylinder and (2) the acceptance criteria for the CSB expandable plugs' preload based on irradiation-induced stress relaxation. In Section 4.3.1 of the LRA, the applicant states that the design cycles for 40-year operation bound the period of extended operation. The applicant evaluated the CSB analysis and determined that the analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The CSB repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB wall. The preload is required to provide proper seating of the plugs and patches and to prevent movement of the plugs due to hydraulic drag loads.

The applicant stated that the original plug preload analysis was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant. This preload analysis was revised for increased 60-year end-of-life fluence and for irradiation-induced relaxation input. The analysis concluded that all the repair plug flange deflection measurement readings are sufficient to meet the minimum required values and maintain the plugs preloaded. The applicant concluded that the CSB repair plugs will perform their intended function for the period of extended plant operation. The CSB plug preload relaxation analysis has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

The applicant indicated in Subsection 4.3.1 of the LRA that the design cycles for 40-year operation bound the period of extended operation. The staff evaluated the CSB analysis and determined that it remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

The staff reviewed the information provided by the applicant in the LRA and concluded that additional information was needed before the safety of the CSB for the period of extended operation could be evaluated. In RAI 4.6.3-1, the staff requested that the applicant provide a detailed description of the fatigue analysis of the CSB middle cylinder with the expandable plugs, and confirm that the fatigue evaluation meets the ASME Section III Class 1 limit fatigue criterion for the period of extended operation.

The applicant responded to RAI 4.6.3-1 in a letter dated October 10, 2002. In its response, the applicant states that the fatigue methodology developed for the CSB repairs employs a conservative method for combining component stresses to obtain stress intensities for the various cyclical loading conditions. The plant design transients and cycles utilized in the fatigue analysis are defined in Section 5.2.1.2 of the Unit 1 UFSAR. These design transients are also applicable to the RV internal components. The design limits for RV internals are specified in Section 4.2.2.1.2 of the Unit 1 UFSAR. For the core support structures, the allowable stress values are those given in the May 1972 drafts of ASME Section III, Subsection NG, and Appendix F, "Rules for the Evaluation of Faulted Conditions." In the fatigue evaluation of the CSB, the full 40-year design transient set was applied, without taking credit for cycles before the CSB damage in 1983. As stated in Subsection 4.3.1 of the LRA, the 40-year design cycles bound the period of extended operation. On this basis, the applicant calculated a CUF of 0.58 for the CSB middle cylinder. The staff finds the applicant's result acceptable because it does not exceed the ASME Section III Class 1 CUF limit of 1.0.

In RAI 4.6.3-2, the staff requested that the applicant provide the source and basis for the data and information that were used to assess irradiation-induced relaxation of the plug preload, which is expected to occur in the CSB expandable plugs at the end of 60 years of reactor operation. In RAI 4.6.3-3, the staff requested that the applicant provide a detailed description of the CSB plug preload analysis, which is based on irradiation-induced stress relaxation, showing that the expandable plugs will continue to perform their function given the predicted fluence, operating temperature, operating hydraulic loads, and thermal deflections for the period of extended operation.

The applicant responded to RAIs 4.6.3-2 and 4.6.3-3 in letters dated October 10, 2002, and November 27, 2002, respectively. In its responses, the applicant states that the preload acceptance criteria for the expandable plugs that were used in the repair of the St. Lucie Unit 1 CSB depend on irradiation-induced stress relaxation, a process in which the stress in the material under load decreases with time. The analysis of the time varying effect of stress relaxation on the preloading of the plugs thus constitutes a TLAA under the provisions of 10 CFR 54.3.

The CSB repair plugs were installed at the end of Cycle 5 as part of the overall St. Lucie Unit 1 CSB repair effort that included removing the thermal shield assembly and repairing damage incurred following a failure of the thermal shield support system. The CSB damage consisted of through-wall cracks and thermal shield support-lug non-through-wall tear-out areas. The through-wall cracks were arrested with circular crack arrestor holes, and the through-wall tear areas were machined out and sealed with patches. The function of the repair plugs is to seal the through-wall crack arrestor holes and the tear-out holes, and to limit or prevent bypass flow leakage through the holes.

The repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB wall. This preload is required to provide proper sealing of the plugs and patches, to prevent movement of the plugs due to hydraulic drag loads, and to keep the plugs tight under anticipated thermal cycling conditions.

A plug consists of a thin-wall cylinder with a preformed flange. The plug is inserted and expanded in the hole, thus bending the flange and preloading the plug. The design of the plugs allows for the preload to be quantified by measuring the deflection of the plug flange, which acts against the outside diameter of the CSB. The preload criteria are defined as the minimum deflection requirements required to maintain the plug preload over the operating life of the plant. The criteria were determined based on the applied hydraulic drag forces, relative thermal expansion effects, and irradiation-induced stress relaxation of the flange/cylinder over the life of the plant.

As part of the 1997 St. Lucie Unit 1 SG replacement effort, the reactor coolant flow rate was increased, which increased the hydraulic drag forces on the plugs. In support of license renewal, the applicant revised the preload analysis to recalculate the preload criteria. The re-analysis utilized the original methodology, updated fluence and irradiation-induced stress relaxation material data input, and reduced temperature and temperature gradients in the CSB.

The applicant then evaluated previously measured deflections against the revised criteria. In accordance with the original evaluation of plug flange deflection measurements, actual measured plug flange deflection must be greater than or equal to the acceptance criteria. The applicant stated that the re-analysis results demonstrate that the plugs have sufficient preload to perform their intended function over the 60-year operating life of the plant. In all cases, actual plug flange deflection measurements exceed the revised acceptance criteria. The re-analysis concludes that the CSB repair plugs will maintain the preload and perform their intended function for the period of extended operation.

The applicant stated in previous reports that the plugs were designed to meet ASME Code Section III Class 1 requirements. The ASME Code, Section III, Subsection NB, has no provision for addressing thermal stress relaxation, since this effect becomes significant above temperatures for which ASME Code materials are specified (700–800 °F). Radiation-induced stress relaxation does occur at normal operating temperatures experienced by the CSB, however, its effect is negligible except for highly stressed members such as the CSB plugs. Therefore, the ASME Cde has no provisions or design criteria for irradiation induced stress relaxation at these temperatures.

By letter dated October 10, 2002, the applicant provided the (proprietary) description of the methodology used in the preload analysis. The staff reviewed the methodology and the updated stress relaxation data on which the analysis is based. The staff determined that the assumptions used in the re-analysis are consistent with acceptable engineering principles, the calculations are consistent with the initial analyses, and that the measured plug deflections meet the acceptance criteria determined by the re-analysis. On the basis of its review, the staff concludes that the applicant provided a reasonable demonstration that the plugs will continue to perform their intended function during the period of extended operation.

4.6.3.3 Conclusions

The staff concludes that the applicant has provided an acceptable demonstration pursuant to 10 CFR 54.21(c)(1) that, for the Unit 1 CSB repair TLAA, analyses have been projected to the end of the period of extended operation and the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff also concludes that the Unit 1 UFSAR supplement contains an appropriate summary description of this TLAA evaluation.

4.6.4 Alloy 600 Instrument Nozzle Repairs

4.6.4.1 Summary of Technical Information in the Application

In Section 4.6.4 of the LRA, the applicant summarizes the process and results of its TLAA related to half-nozzle repairs of leaking Alloy 600 instrumentation nozzles to the RCS hot-leg piping or pressurizers. The staff reviewed this section to determine whether the applicant provided adequate information to meet the requirements of 10 CFR 54.21(c). The UFSAR supplement summary descriptions for the TLAA are given in Section 18.3.8 of LRA Appendix A1 for St. Lucie Unit 1 and Section 18.3.7 of LRA Appendix A2 for St. Lucie Unit 2.

Small-diameter Alloy 600 nozzles, such as pressurizer and RCS hot leg instrumentation nozzles in Combustion Engineering-designed PWRs, have developed leaks or partial through-wall cracks as a result of PWSCC. In Section 4.6.4 of the LRA, the applicant indicates that Units 1 and 2 have experienced instances of leakage from Alloy 600 instrument nozzles in the RCS. The applicant states that it has used an alternative repair technique known as the "half-nozzle" weld repair as the method for repairing leaking Alloy 600 instrument nozzles in the RCS. The applicant indicates that four leaking pressurizer steam space instrument nozzles at Unit 2, and one leaking hot leg instrument nozzle at Unit 1, were repaired using half-nozzle repair methods.

4.6.4.2 Staff Evaluation

In a half-nozzle repair technique, the leaking (cracked) Alloy 600 nozzle is cut above the partial-penetration J-groove weld that was used to join the nozzle to the RCS hot leg piping or pressurizer shell. The section of the nozzle that is proximal to the outer surface of the pressure boundary component is removed and replaced with a short Alloy 690 nozzle section. The inserted Alloy 690 nozzle section is then welded to the pressure boundary component's outside surface. The half-nozzle repair method leaves a short section of the original nozzle attached to the inside surface with the J-groove weld, and exposes the ferritic (i.e., low-alloy steel or carbon steel) pressure boundary material to the borated water conditions of the reactor coolant.

In Section 4.6.4 of the LRA, the applicant indicated that a fracture mechanics analysis was submitted to the NRC to support the Unit 2 pressurizer steam space half-nozzle repairs performed in 1994. The fracture mechanics analysis justified the acceptability of indications in the J-groove weld based on a postulated flaw size and flaw growth considering the applicable design cycles. Based on the results of the analysis, the applicant concluded that the postulated flaw size for the worst-case instrument nozzle was acceptable for the remaining design life of the plant (30 years, or 75 percent of the original 40-year plant design life).

The applicant also indicated that a half-nozzle repair was implemented on a Unit 1 RCS hot leg instrumentation nozzle in April 2001. In response to NRC questions regarding this repair, FPL documented that the indications in the J-groove weld were bounded by the fracture mechanics analysis provided in CEOG Topical Report No. CE NPSD-1198-P, Revision 0, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/ Replacement Programs," which was submitted on February 15, 2001, to the NRC for review and approval. The applicant also documented in that response that the CEOG topical report is also applicable to the Unit 2 pressurizer steam space nozzle repairs performed in 1994.

The staff issued three RAIs on the St. Lucie half-nozzle designs to address the three plant-specific assessments requested in the staff's SE on Topical Report No. CE NPSD-1198-P, Revision 0, by letter to the CEOG dated February 8, 2002. In RAI 4.6.4-1, the staff requested the applicant to demonstrate that the half-nozzle designs would have acceptable structural integrity against unacceptable crack growth due to thermal fatigue and would be acceptable for service through the expiration of the extended operating licenses for Units 1 and 2. In RAI 4.6.4-2, the staff requested the applicant to demonstrate that the half-nozzle designs will have sufficient structural integrity against loss of material by corrosion and will meet their minimum wall thickness requirements through the expiration of the extended period of operation for the units. In RAI 4.6.4-3, the staff requested justification and validation of the CEOG's conclusion that growth of the existing flaw in the original Alloy 600 J-groove weld material by stress corrosion would not be a plausible effect during the period of extended operation for the units.

The applicant submitted its responses to RAIs 4.6.4-1, 4.6.4-2, and 4.6.4-3, by letter dated October 10, 2002. In the response of October 10, 2002, the applicant summarized the results of the CE's original fatigue crack growth analysis, boric acid wastage analysis, and stress corrosion-induced crack growth analysis as provided in CE Proprietary Topical Report CE NPSD-1198-P, Revision 00. In response to RAI 4.6.4-3, the applicant stated that the water chemistry program controls the hydrogen overpressure and dissolved oxygen, halide ion, and sulfate ion impurity levels in the reactor coolant to acceptable concentrations, and therefore growth of the cracks in leaking Alloy 600 nozzle welds by stress corrosion into the adjacent ferritic shells or piping is not plausible. The applicant stated that reactor coolant chemistry records implemented over the past few years confirms this. This meets the staff's assessment criteria previously stated to determine the susceptibility of cracks to growth from stress corrosion. Based on this response the staff concurs that stress-corrosion-induced growth of cracks in leaking Alloy 600 nozzle welds will not be a problem for half-nozzle designs implemented at St. Lucie, and RAI 4.6.4-3 is therefore resolved.

In regard to the resolution of RAIs 4.6.4-1 and 4.6.4-2, Westinghouse Electric Corporation has revised CE Proprietary Topical Report CE NPSD-1198-P, Revision 00, since the staff's review of the report was issued (as given in the staff's SE of February 8, 2002), and since the applicant's responses to RAIs 4.6.4-1 and 4.6.4-2 were issued (October 10, 2002). The revisions of the topical report address potential issues with the original boric acid wastage analysis for the half-nozzle designs that were raised as a result of the boric acid corrosion (wastage) event of the Davis Besse reactor vessel (RV) head and to address a design calculation error discovered by Westinghouse in the original fatigue crack growth analysis for the half-nozzle designs. The revised report is provided in Class 2 Proprietary WCAP-15973-P, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs (November 2002)," which was submitted to the NRC for review and approval in Combustion Engineering Owners Group letter CEOG-02-243, dated November 11, 2002. The report is applicable to the St. Lucie half-nozzle designs. To supplement its response to RAI 4.6.4-1, the applicant submitted Class 2 Proprietary Calculation CN-CI-02-60, "Evaluation of Fatigue Crack Growth Associated with Small Diameter Nozzles for St. Lucie 1 & 2," as the corresponding St. Lucie-specific fatigue crack growth analysis for the St. Lucie half nozzle designs. The staff is currently reviewing the acceptability of WCAP-15973-P and Class 2 Proprietary Calculation CN-CI-02-60. In response to RAI 4.6.4-2, the applicant also indicated that FPL continues to rely on the topical report's generic boric acid corrosion rate assessment as the basis for evaluating the susceptibility of the adjoining ferritic Class 1 components to boric acid corrosion.

In addition, by letter dated January 8, 2003, the applicant submitted a relief request for approval of the half-nozzle designs implemented at the St. Lucie Nuclear Station. In this relief request, submitted pursuant to 10 CFR 50.55a(a)(3)(ii), the applicant requested approval of an alternative to Paragraph IWB-3132.3 of the 1989 Edition of Section XI to the ASME Boiler and Pressure Vessel Code, which requires that, for a component containing a flaw, that the "component or portion of the component containing the flaw be replaced." The staff is currently in the progress of reviewing the acceptability of the applicant's relief request of January 8, 2003, for the extended period.

The staff stated in its SER with open items that the acceptability of the TLAA for the St. Lucie half-nozzle designs was pending approval of WCAP-15973-P, Class 2 Proprietary Calculation CN-CI-02-60, and submittal of an acceptable relief request for the half-nozzle designs for the periods of extended operation for St. Lucie Units 1 and 2. Therefore, to address the applicant's responses to RAIs 4.6.4-1 and 4.6.4-2, the staff issued open item 4.6.4-1 and informed the applicant that the TLAA for the half-nozzle designs was pending acceptable approval of WCAP-15973-P, Class 2 Proprietary Calculation CN-CI-02-60, and submittal of an acceptable relief request for the half-nozzle designs for the period of extended operation.

In a letter dated April 25, 2003 (FPL Letter L-2003-096), the applicant submitted a supplemental response to Open Item 4.6.4-1. In this response, the applicant confirmed that the fatigue crack growth assessment for the half-nozzle replacement designs is given in Class 2 Proprietary Calculation CN-CI-02-60. The applicant stated that an ASME Section XI relief request for the half-nozzle designs was submitted for NRC review and approval on January 8, 2003. This relief request is currently under review by the staff. In its response, the applicant committed the following:

Implement all reasonable alternative inspection/evaluation methods that may be required by the NRC, as appropriate, as conditions for approval of the relief request. Subsequent to the disposition of the relief request and prior to the period of extended operation, the TLAAs for the St. Lucie Units 1 and 2 half-nozzle replacement designs will be dispositioned pursuant to 10 CFR 54.21(c)(1). These TLAAs shall address: 1) the potential growth of the original flaw due to thermal or mechanical cycling, and 2) the potential wastage of the ferritic material that is adjacent to the half-nozzle configuration and exposed to borated reactor coolant. If acceptability of the St. Lucie Units 1 and 2 half-nozzle designs cannot be demonstrated for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(i) or 54.21(c)(1)(ii), then these TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) which may include appropriate nozzle replacement to comply with ASME Section III and ASME Section XI replacement criteria.

This commitment is tracked as Item 21 of Table 1 to SER Appendix D (i.e., the commitment table for St Lucie Unit 1) and Item 19 of Table 2 to SER Appendix D (i.e., the commitment table for St. Lucie Unit 2). Based on the applicant's commitment, the staff considers RAIs 4.6.4-1 and 4.6.4-2 and Open Item 4.6.4-1 closed.

4.6.4.3 UFSAR Supplement

The applicant provides the UFSAR supplement summary descriptions for the TLAAs on the Alloy 600 instrument nozzle repairs in Section 18.3.8 of Appendix A1 and Section 18.3.7 of Appendix A2 to the LRA. The applicant amended the UFSAR supplement summary descriptions for the TLAA in FPL Letter L-2002-165 (April 10, 2002) and FPL letter L-2003-096 (April 25, 2003) in order to reflect information in the applicant responses to RAIs 4.6.4-1 and 4.6.4-2 and Open Item 4.6.4-1. The staff reviewed the UFSAR supplement summary descriptions for the TLAA as given in Section 18.3.8 of Appendix A1 and Section 18.3.7 of Appendix A2 to the LRA, as amended in FPL Letters L-2002-165 and L-2003-096. The staff determined that the UFSAR summary descriptions for the TLAA on the half-nozzle designs, as amended, provide both a sufficient description of the analyses covered by the scope of the TLAA and a sufficient summary of the actions the applicant will take to resolve the TLAA for the St. Lucie half-nozzle designs. This commitment will ensure compliance with the requirements of 10 CFR 54.21(c)(1) and 10 CFR 50.55a(a)(3). The staff therefore concludes that the proposed changes to the UFSAR supplement summary descriptions for the TLAA are acceptable.

4.6.4.4 Conclusions

The staff concludes that the applicant has provided an acceptable demonstration pursuant to 10 CFR 54.21(c)(1) that, for the half-nozzle designs TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplements contain an appropriate summary description of this TLAA evaluation for the period of extended operation.

5. REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

On February 7, 2003, the NRC staff issued its safety evaluation report (SER) with open items related to the license renewal of St. Lucie Nuclear Plant, Units 1 and 2. On April 9, 2003, the Advisory Committee on Reactor Safeguards (ACRS) conducted a review of the 10 CFR Part 54 portion of the St. Lucie license renewal application and the SER with open items. The staff finalized and issued its SER related to the license renewal of the St. Lucie Nuclear Plant, Units 1 and 2, on July 7, 2003.

During its 505th meeting on September 11, 2003, the ACRS full committee completed its review of the St. Lucie license renewal application and the staff's SER. The ACRS documented its findings in a letter to the Commission dated September 17, 2003. A copy of this ACRS letter is attached.

September 17, 2003

The Honorable Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE ST. LUCIE NUCLEAR PLANT UNITS 1 AND 2

Dear Chairman Diaz:

During the 505th meeting of the Advisory Committee on Reactor Safeguards on September 10-13, 2003, we completed our review of the License Renewal Application (LRA) for the St. Lucie Nuclear Plant Units 1 and 2, and the related final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee reviewed this LRA and the staff's initial SER during a meeting on April 9, 2003. During our review, we had the benefit of discussions with representatives of the NRC staff and Florida Power and Light Company (FPL or the applicant). We also had the benefit of the documents referenced.

CONCLUSION AND RECOMMENDATION

1. The programs instituted by FPL to manage age-related degradation are appropriate and provide reasonable assurance that St. Lucie Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

2. The FPL application for renewal of the operating licenses for St. Lucie Units 1 and 2 should be approved.

BACKGROUND AND DISCUSSION

This report fulfills the requirement of 10 CFR 54.25, which states that the ACRS should review and report on all license renewal applications. St. Lucie Units 1 and 2 are 2700 MWt Combustion Engineering-designed pressurized water reactors in large dry containments. In its application, FPL requested renewal of the operating licenses for St. Lucie Units 1 and 2 for 20 years beyond the current license term, which expires on March 1, 2016 for Unit 1 and April 6, 2023 for Unit 2. St. Lucie Unit 1 was licensed approximately 7 years before St. Lucie Unit 2. During these 7 years, significant events occurred at operating nuclear plants, including the Three Mile Island Unit 2 event and the Browns Ferry Fire event. The lessons learned from these events resulted in design differences between St. Lucie Unit 1 and Unit 2, which are appropriately reflected in the LRA.

The final SER documents the results of the staff's review of the information submitted by the applicant, including commitments that were necessary to resolve open items identified by the staff in the initial SER. In particular, the staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are subject to aging management; the integrated plant assessment process; the applicant's identification of the possible aging mechanisms associated with passive, long-lived components; and the adequacy of the applicant's aging management programs.

The staff also conducted several inspections at St. Lucie, including an audit of the adequacy of the scoping and screening methodology and its implementation to ensure that SSCs within the scope of license renewal have been appropriately identified; an inspection of the aging management programs to confirm that existing programs are functioning well and to examine the applicant's plans for establishing new and enhanced aging management programs; and a walkdown of plant systems to assess how the systems are being maintained.

On the basis of our review of the final SER, LRA, and the inspection report, we conclude that the process implemented by the applicant to identify SSCs that are within the scope of license renewal was effective, the applicant performed a comprehensive aging management review of such SSCs, and the staff and the applicant appropriately identified all SSCs that are within the scope of license renewal. The applicant stated that it plans to implement 70 to 80% of the commitments for license renewal prior to the issuance of the renewed licenses. We agree with the staff's conclusion that all open and confirmatory items have been closed appropriately and there are no issues that preclude renewal of the operating licenses for St. Lucie Units 1 and 2.

The groundwater at the St. Lucie site is characterized by high concentrations of chlorides and sulfates that create an aggressive environment for concrete structures. The applicant has committed to enhance those elements of the St. Lucie's Systems and Structures Monitoring Program that deal with inspections of accessible and inaccessible concrete structures. This Program will be enhanced to include specific provisions consistent with industry standards and inspection guidelines for monitoring concrete structures. The monitoring plan for inaccessible concrete structures includes inferring material conditions of inaccessible structures from inspection of accessible structures exposed to groundwater and opportunistic inspections of below-grade concrete. The applicant stated that during construction, concrete of sufficient quality was used to inhibit degradation of concrete and protect the embedded reinforcing steel. No concrete degradation has been found during opportunistic inspections of inaccessible concrete structures performed in 1997 and 2002. Based on this information, we agree with the staff that the enhancements proposed by the applicant provide reasonable assurance that the integrity of concrete structures at St. Lucie will be adequately monitored during the period of extended operation.

St. Lucie's Alloy 600 Inspection Program includes provisions and commitments for inspecting reactor pressure vessel (RPV) head penetration nozzles. The applicant has performed visual and ultrasonic inspections of the RPV heads of both units, and no evidence of leakage has been identified. An axial flaw was identified and repaired in two control element drive mechanism penetrations of Unit 2. The applicant has ordered replacement heads for both units. The applicant will continue to participate in the industry program for assessing and managing primary water stress corrosion cracking (PWSCC) in Alloy 600 RPV head penetration nozzles, and has committed to perform inspections as recommended by this program. Based on the applicant's responses to related NRC bulletins and its commitment to participate in the industry's program for assessing and managing PWSCC of the RPV head penetration nozzles, there is reasonable assurance that the integrity of St. Lucie Units 1 and 2 RPV heads will be adequately monitored and maintained.

The applicant identified those components at St. Lucie Units 1 and 2 that are supported by time-limited aging analyses (TLAAs) and provided data to demonstrate that the components have sufficient margin to operate properly during the period of extended operation.

Two of the TLAAs are unique to St. Lucie because they qualify repairs of long-lived passive components for the period of extended operation. The first addresses the repairs that took place at St. Lucie Unit 1 to deal with damage identified in 1983 in the core support barrel (CSB) and thermal shield assemblies. The thermal shield was permanently removed. Four lugs were found to have separated from the CSB and through-wall cracks were found adjacent to the lug areas. These cracks were arrested with crack-arrestor holes that were sealed by inserting expandable plugs.; The repairs were qualified for the remaining life of the plant and have been repeatedly inspected and found to be effective. In order to qualify these repairs for 60-years life, the fatigue analysis of the CSB middle cylinder and the acceptance criterion for the expandable-plugs preload based on irradiation-induced stress relaxation had to be repeated to cover 60-years of operation. The staff performed a thorough review of this TLAA and found it acceptable. The work presented by the applicant and the staff, and the inservice inspections to which the CSB will continue to be subjected provide reasonable assurance that the integrity of the CSB will be adequately monitored and maintained during the period of extended operation.

The second TLAA involves the 1994 half-nozzle repair of four leaking pressurizer instrument nozzles at Unit 2 and the 2001 half-nozzle repair of one leaking hot leg instrument nozzle at Unit 1. These repairs need to be qualified for the extended period of operation. The staff's review of the supporting analyses, which includes a request for relief from certain requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, is still under way. The applicant has committed that if the acceptability of the half-nozzle design cannot be demonstrated for the period of extended operation, then this TLAA will be dispositioned by other means, possibly including appropriate nozzle replacement to comply with ASME Code replacement criteria. This commitment ensures that these repairs will be adequately qualified for the period of extended operation.

The applicant and the staff have identified plausible aging effects associated with passive, long-lived components. Adequate programs have been established to manage the effects of aging so that St. Lucie Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

Sincerely,
Original signed by
Mario V. Bonaca
Chairman

<u>References</u>:

1 U.S. Nuclear Regulatory Commission, NUREG -xxxx, "Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2," July 2003.

2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report with Open Items Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2," February 2003.

3. Letter dated November 29, 2001 from J. A. Stall, Florida Power and Light Company, to U.S. Nuclear Regulatory Commission, transmitting Application to Renew the Operating Licenses of St. Lucie Nuclear Plant, Units 1 and 2.
4. U. S. Nuclear Regulatory Commission, Region II Inspection Report No. 50-335/03-03, 50-389/03-03.

6. CONCLUSIONS

The staff reviewed the St. Lucie Nuclear Plant, Units 1 and 2, license renewal application in accordance with Commission regulations and the NRC "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The Commission's regulatory standards for issuance of a renewed license in 10 CFR 54.29.

In the SER with Open Items issued on February 7, 2003, the staff identified a number of open and confirmatory items. All of these items have been resolved, as discussed in this SER. On the basis of its evaluation of the application, as discussed above, the staff concludes the following:

5. actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1); and

6. actions have been identified and have been or will be taken with respect to time-limited aging analyses that been identified to require review under 10 CFR 54.21(c).

Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis for the St. Lucie Nuclear Plant, Units 1 and 2. The staff notes that the requirements of Subpart A of 10 CFR Part 51 are documented in the final plant-specific supplement to the Generic Environmental Impact Statement issued on May 16, 2003.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of the routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and the Florida Power and Light Company (FPL), and other correspondence regarding the NRC staff's review of the St. Lucie Nuclear Plant Units 1 and 2 (under Docket Numbers 50-335 and 50-389), for license renewal application (LRA).

October 30, 2000	In a letter (signed by R. Kundalkar), FPL submitted a request for an exemption from the scheduler requirement of 10 CFR 54.17(c).
February 27, 2001	In a letter (signed by B. Moroney), NRC notified FPL that it had approved the request for an exemption from the scheduler requirement of 10 CFR 54.17(c).
October 19, 2001	In a letter (signed by J. Stall), FPL provided the NRC a schedule for submittal of its application for renewed operating licenses.
November 29, 2001	In a letter (signed by J. Stall), FPL submitted its LRA for St. Lucie Nuclear Plant Units 1 and 2. ML013400473
November 29, 2001	In a letter (signed by D. Jernigan), FPL submitted license renewal boundary drawings. ML013480240
December 19, 2001	In a letter (signed by C. Grimes), NRC notified FPL concerning the receipt and availability of the LRA. ML013400473
December 20, 2001	In a letter (signed by D. Jernigan), FPL submitted additional copies of the LRA. ML020160029
January 8, 2002	In a letter (signed by D. Jernigan), FPL submitted a revised page for the LRA. ML020110489
January 24, 2002	In a letter (signed by C. Grimes), NRC notified FPL of the acceptability and sufficiency for docketing, proposed review schedule, and opportunity for a hearing regarding the LRA. ML020240333.
February 18, 2002	In a letter (signed by D. Jernigan), FPL submitted additional copies of the "Application for Renewed Operating Licenses for St. Lucie Nuclear Plant, Units 1 and 2." ML020520515
February 22, 2002	In a letter (signed by C. Grimes), NRC informed FPL of its intent to prepare an environmental statement and to conduct scoping. ML020530588
April 15, 2002	In a letter (signed by N. Dudley), NRC notified FPL of a revision to the schedule for the conduct of the review of the LRA. ML021050186

May 7, 2002	In a letter (signed by M. Masnik), NRC provided FPL a summary of the scoping meeting held in support of the environmental review (RAIs) of the LRA. ML021300604
May 7, 2002	In a letter (signed by M. Masnik), NRC provided FPL requests for additional information related to the staff's review of severe accident mitigation alternatives. ML021340363
June 3, 2002	In a letter (signed by P.T. Kuo), NRC requested confirmation of the U.S. Department of Commerce position regarding Federally protected species that may be affected by the operation of St. Lucie Units 1 and 2. ML021570345
June 19, 2002	In a letter (signed by N. Dudley), NRC provided a summary of the May 28 and 29, 2002, teleconferencing calls with FPL regarding potential RAIs concerning its review of the LRA. ML021780091
June 21, 2002	In a letter (signed by J. Cushing), NRC provided a summary of the May 15 and 16, 2002, meeting with FPL regarding potential RAIs concerning its review of the LRA. ML021780147
June 25, 2002	In a letter (signed by D. Jernigan), FPL provided a response to NRC concerning RAIs related to the staff's review of severe accident mitigation alternatives associated with the LRA. ML021820106
July 1, 2002	In a letter (signed by N. Dudley), NRC provided FPL RAIs regarding its review of Sections 2.0, 3.0, 4.0, and Appendix B of the LRA. ML021830288
July 1, 2002	In a letter (signed by N. Dudley), NRC provided FPL RAIs regarding its review of Section 3.3 of the LRA. ML021830321
July 8, 2002	In a letter (signed by M. Masnik), NRC provided FPL the environmental scoping summary report associated with its review of the LRA. ML021920466
July 18, 2002	In a letter (signed by N. Dudley), NRC provided FPL RAIs regarding its review of Sections 2.0, 3.0, 4.0, and Appendix B of the LRA. ML022030456
July 24, 2002	In a letter (signed by P.T. Kuo), NRC informed the U.S. Fish and Wildlife Service of its biological assessment of 14 Federally protected species in the vicinity of the St. Lucie Nuclear Plant. ML022060314
July 29, 2002	In a letter (signed by N. Dudley), NRC provided FPL RAIs regarding its review of Sections 2.2, 2.3, and Appendix B of the LRA. ML022110165

July 30, 2002	In a letter (signed by J. Powers) the U.S. Department of Commerce provided clarification to NRC regarding the effect of the cooling water intake system on local wildlife. ML022200253
July 31, 2002	In a meeting summary (signed by N. Dudley), NRC summarized the June 10 and 11, 2002, meeting concerning draft RAIs. ML022130182
August 26, 2002	In a letter (signed by D. Jernigan), FPL provided NRC with a supplemental response to RAIs associated with the environmental report of the LRA. ML022410053
September 26, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning the scoping and screening methodology in Section 2.1 of the LRA. ML022700567
September 26, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning the AMR results in Section 3.0 of the LRA. ML022740116
September 26, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning AMR results—auxiliary systems in Section 3.3 of the LRA. ML022740106
September 26, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning the AMPs in Appendix B of the LRA. ML022740199
September 27, 2002	In a meeting summary (signed by N. Dudley), NRC summarized the August 15 and 16 and September 4 and 5, 2002, meetings concerning the applicant's draft responses to RAIs. ML022700262
	the FPL draft responses discussed during the meetings were e-mailed to NRC. The six e-mails contained responses to RAIs concerning the following LRA sections.

Scoping and Screening Methodology, received 7/19/02	ML022700426
Scoping and Screening Results, received 8/6/02	ML022700434
Aging Management Reviews, received 8/6/02	ML022700446
Auxiliary Systems AMRs, received 8/6/02	ML022700453
Time-Limited Aging Analyses ,received 8/26/02	ML022700472
Aging Management Programs, received 8/26/02	ML022700477

October 3, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning the scoping and screening results in Section 2.0 of the LRA. ML022810608
October 7, 2002	In a letter (signed by C. Casto), NRC announced a public meeting on October 25, 2002, concerning the results of the NRC's first inspection of the license renewal program. ML022800527

October 10, 2002	In a letter (signed by N. Dudley), NRC provided FPL a revised schedule for the conduct of its review of the LRA. ML022900065
October 10, 2002	In a letter (signed by D. Jernigan), FPL provided NRC responses to RAIs concerning the time-limited aging analyses in Section 4.0 of the LRA. ML022890457
October 19, 2002	In a memorandum (signed by N. Dudley), NRC provided FPL a summary of an October 17, 2002, telephone call concerning responses to RAIs pertaining to the LRA. ML022940378
November 19, 2002	In a letter (signed by N. Dudley), NRC provided FPL an exemption from the requirements regarding the schedule for submitting amendments to the LRA. ML023240285
November 27, 2002	In a memorandum (signed by N. Dudley), NRC provided FPL a summary of meetings on November 6 and 7, 2002, and phone calls on November 20, 21, and 25, 2002, concerning FPL's draft supplemental responses to RAIs. ML023330412
November 27, 2002	In a letter (signed by D. Jernigan), FPL provided NRC supplemental responses to RAIs pertaining to the LRA. ML023380251
December 5, 2002	In a letter (signed by H. Christensen), NRC provided Inspection Report 50-335/02-07 50-389/02-07 with results of scoping and screening inspection. ML023430047
December 23, 2002	In a letter (signed by D. Jernigan), FPL provided NRC supplemental responses to RAIs pertaining to the LRA. ML023600436
January 7, 2003	In a letter (signed by M. Masnik), NRC provided FPL a summary of a public meeting on December 3, 2002, concerning the draft Supplemental Environmental Impact Statement(SEIS) for St. Lucie Units 1 and 2. ML030060091
January 9, 2003	In a letter (signed by D. Jernigan), FPL provided NRC comments on the draft SEIS for license renewal. ML030270297
February 4, 2003	In a letter (signed by D. Jernigan), FPL provided NRC a list of license renewal commitments. ML030370120
February 7, 2003	In a letter (signed by P. T. Kuo), NRC provided draft SER with open items for applicant's review and comment. ML030410192
February 11, 2003	In a memorandum (signed by N. Dudley), NRC provided FPL a summary of telephone calls of December 3 and 23, 2002, January 3 and 31, and February 3, 2003, concerning the applicant's draft supplemental response to the RAIs. ML030430114

March 7, 2003	In a letter (signed by H. Christensen), NRC provided Inspection Report 50-335/2003-03 and 50-389/2003-03 with the results of the AMP inspection. ML030710192.
March 11, 2003	In a letter (signed by N. Dudley), NRC provided errata to license renewal SER with open item. ML030710193
March 27, 2003	In a letter (signed by D. Jernigan), FPL provided the annual amendment to the St. Lucie Units 1 and 2 LRA. ML030910116
March 27, 2003	In a letter (signed by D. Jernigan), FPL provided comments on SER with open items. ML030910258
March 28, 2003	In a letter (signed by D. Jernigan), FPL provided SER open item and confirmatory item responses and revised LRA Appendix A. ML030910633
April 14, 2003	In a memorandum (signed by T. Liu), NRC provided FPL a summary of the March 18 and 25, 2003, telephone calls concerning the draft supplemental response to the SER open item on fuse holders. ML0310504
April 15, 2003	In a memorandum (signed by T. Liu), NRC provided FPL a summary of the April 3, 2003, telephone calls concerning the draft responses to the SER open item on Alloy 600 instrument nozzle repairs. ML031060135
April 22, 2003	In a meeting summary (signed by T. Liu), NRC summarized the March 5, 2003 meeting and March 10, 2003, telephone calls concerning the draft responses to SER open items. ML031103656
April 25, 2003	In a letter (signed by W. Jefferson), FPL provided a supplemental response to an SER open item concerning Alloy 600 instrument nozzle repairs. ML031190633
May 8, 2003	In a letter (signed by N. Dudley), the NRC informed Westinghouse Electric Company that it agreed that specific proprietary commercial information should be withheld from public disclosure. ML031280644
May 19, 2003	In a letter (signed by M. Masnik), the NRC provided FPL a copy of the Final Supplement 11 to the Generic Environmental Impact Statement (GEIS) regarding license renewal for St. Lucie, Units 1 and 2. ML031360686
May 12, 2003	In a letter (signed by N. Dudley), the NRC provided FPL a request for clarification related to a supplemental response to a request for additional information concerning the nonsegregated-phase bus. ML031320761
May 30, 2003	In a letter (signed by W. Jefferson), FPL provided a supplemental response to SER open items concerning intake cooling water supply to

	the spent fuel pool and pressurizer nozzle thermal sleeves. ML031550376
June 6, 2003	In a memorandum (signed by T. Liu), NRC summarized the telephone calls on April 23 and May 7, 2003 and a meeting on May 21, 2003 concerning the draft responses to open items in SER. ML031570354. The draft responses included the following: L-2003-070, dated March 28, 2003 L-2003-130, draft supplemental responses received May 19, 2003 L-2003-135, draft supplemental responses received May 19, 2003 E-mail communication between NRC and FPL on May 28, 2003
June 10, 2003	In a letter (signed by W. Jefferson), FPL provided a supplemental response to a SER open item concerning clarification to RAI 2.1-2 response regarding station blackout. ML031630886
June 23, 2003	In a telephone call summary (signed by T. Liu), NRC summarized the June 17, 2003, telephone call concerning a SER open item regarding the aging management review for the pressurizer surge and spray nozzle thermal sleeves. ML031740717
June 23, 2003	In a letter (signed by W. Jefferson), FPL provided a supplemental response to a SER open item concerning the aging management review for the pressurizer surge and spray nozzle thermal sleeves. ML031770044
July 7, 2003	In a letter (signed by P.T. Kuo), the NRC issued its safety evaluation report related to the license renewal of St. Lucie, Units 1 and 2. ML031890049
October **XX**, 2003	In a letter (signed by M. Bonaca), the Advisory Committee on Reactor Safeguards provided its conclusions and recommendations on the renewal of the operating licenses for St. Lucie, Units 1 and 2. **ML......**

APPENDIX B
REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for St. Lucie Units 1 and 2 under Docket Numbers 50-335 and 389.

American Concrete Institute (ACI)

ACI 201.2R-77, *Guide for Making a Condition Survey of Concrete in Service*

ACI 224.1R, *Causes, Evaluation and Repairs of Cracks in Concrete Structures.*

ACI 318-63, *Building Code Requirements for Reinforced Concrete.*

ACI 349.3R, *Evaluation of Existing Nuclear Safety-Related Concrete Structures.*

American National Standards Institute (ANSI)

ANSI/ISA-S7.3, *Quality Standard for Instrument Air, Instrument Society of America.*

ANSI/ANS-56.8, *Containment System Leakage Testing Requirements.*

ANSI B30.16, *Overhead Hoists (Underhung)*, American National Standard.

ANSI B30.2.0, *Overhead and Gantry Cranes, Section 2-2, Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks, and Slings*, American National Standard.

ANSI B31.1, *USA Standard Code for Pressure Piping*, 1968.

ANSI B31.7,

ANSI N1B.2,

American Society of Mechanical Engineers (ASME)

ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, *Class 1 Components.*

ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, *Core Support Structures.*

ASME Boiler and Pressure Vessel Code, Section III, *Class 2 and 3 Piping Failures.*

ASME Boiler and Pressure Vessel Code, Section III, Subsection ND, *Class 3 Rules for Construction of Nuclear Power Plant Components.*

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ML031570360

APPENDIX C
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APPENDIX D
COMMITMENTS LISTING

During the review of FPL's LRA by the NRC staff, the applicant made commitments to provide aging management programs to manage aging effects on structures and components prior to the expiration of its current operating license terms. The following tables list these commitments along with their implementation schedule for each unit.

Table 1 - License Renewal Commitment Listing for St. Lucie Unit 1

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
1	Perform a visual inspection to determine the extent of loss of material due to pitting and microbiologically induced corrosion on the external surfaces of the buried pipe that connects the St. Lucie Units 1 and 2 Condensate Storage Tanks.	18.1.1, Condensate Storage Tank Cross-Connect Buried Piping Inspection	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.1
2	Perform inspections on the surfaces of piping and components to determine if galvanic corrosion is active in systems where it is not expected.	18.1.2, Galvanic Corrosion Susceptibility Inspection Program	Prior to the end of the initial operating license term; additional inspections based on results.	LRA Appendix B, Subsection 3.1.2 Response to RAI B.3.1.2-1 (FPL letter L-2002-222)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
3	Perform examinations using volumetric techniques of the internal surfaces of stainless steel Auxiliary Feedwater piping downstream of the recirculation orifices.	18.1.3, Pipe Wall Thinning Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.3 Responses to RAIs B.3.1.3-1 and B.3.1.3-2 (FPL letter L-2002-166)
4	Submit a report summarizing the aging effects applicable to reactor vessel internals including a description of the inspection plan.	18.1.4, Reactor Vessel Internals Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.4 Response to RAI 3.1-1 (FPL letter L-2002-157)
5	Perform a one-time inspection of the reactor vessel internals.	18.1.4, Reactor Vessel Internals Inspection Program	During the period of extended operation.	LRA Appendix B, Subsection 3.1.4
6	Submit a report summarizing the inspection plan for small bore Class 1 piping prior to implementation.	18.1.5, Small Bore Class 1 Piping Inspection	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.5 Response to RAI B.3.1.5-1 (FPL letter L-2002-166)
7	Perform volumetric inspections of a sample of small bore Class 1 piping.	18.1.5, Small Bore Class 1 Piping Inspection	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.5 Response to RAI B.3.1.5-1 (FPL letter L-2002-166)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
8	Implement the Thermal Aging Embrittlement of CASS Program.	18.1.6, Thermal Aging Embrittlement of CASS Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.6
9	Perform inspections and examinations of the reactor vessel head, incorporate NRC requirements, FPL responses to NRC IE Bulletins, and industry recommendations, including the EPRI Materials Reliability Project.	18.2.1, Alloy 600 Inspection Program	On-going.	LRA Appendix B, Subsection 3.2.1 Response to RAI B.3.2.1-1 (FPL letter L-2002-166)
10	Enhance the ASME Section XI Subsection IWB, IWC, IWD Inservice Inspection Program to: - Perform VT-1 inspections of the core stabilizing lugs and core support lugs, and - Evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue.	18.2.2.1, ASME Section XI Subsection IWB, IWC, IWD Inservice Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.2.1
11	Revise the Boraflex Surveillance Program to include areal density testing (in lieu of blackness testing) of the encapsulated Boraflex material in the spent fuel storage racks.	18.2.3, Boraflex Surveillance Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.3
12	Expand the scope of the Boric Acid Wastage Surveillance Program to include Waste Management components in the scope of license renewal.	18.2.4, Boric Acid Wastage Surveillance Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.4
13	Revise procedures to provide guidance in the event that fatigue design cycle limits are approached.	18.2.7, Fatigue Monitoring Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.7

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
14	Incorporate NFPA-25 testing of wet pipe sprinklers into the Fire Protection Program.	18.2.8, Fire Protection Program	Prior to 50 years from initial operating license.	Response to RAI B.3.2.8-6 (FPL letter L-2002-222)
15	Expand the scope of the Flow Accelerated Corrosion Program to include internal and external loss of material of drain lines and selected steam traps.	18.2.9, Flow Accelerated Corrosion Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.9
16	Enhance the Periodic Surveillance and Preventive Maintenance Program to include components such as filter housings, radiator fins, flexible hoses, door seals, and expansion joints.	18.2.11, Periodic Surveillance and Preventive Maintenance Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.11
17	Program documentation will be enhanced to integrate all aspects of the four subprograms that makeup the Reactor Vessel Integrity Program.	18.2.12, Reactor Vessel Integrity Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.12

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
18	Enhance the Systems and Structures Monitoring Program to include: - Monitoring of the interior surfaces of below groundwater concrete, and examination of a representative sample of below groundwater concrete, when excavated for any reason, - Aging management of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion, and - Aging management of accessible reinforced concrete and reinforced masonry block walls.	18.2.14, Systems and Structures Monitoring Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.14 Responses to RAIs 3.5-9 and 3.5-10 (FPL letter L-2002-157) Response to RAI B.3.2.14-2 (FPL letter L-2002-166) Response to RAI 3.5-12 (FPL Letter L-2002-241)
19	Establish an aging management program to address non-EQ cables and connections in the Containment. The non-EQ cables and connections managed by this program will include those associated with sensitive, low-level signal circuits (source, intermediate, and power range neutron detectors). Complete the first inspection described in the aging management program.	New section to be added	Prior to the end of the initial operating license term.	Responses to RAIs 3.6-1 and 3.6-2 (FPL letter L-2002-222)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
20	Address environmentally assisted fatigue of the pressurizer surge line using one or more of the following approaches: - Further refinement of the fatigue analysis to lower the CUF(s) to below 1.0, or - Repair of the affected locations, or - Replacement of the affected locations, or - Manage the effects of fatigue by an NRC approved inspection program.	18.3.2.3, Environmentally Assisted Fatigue	Prior to the period of extended operation.	LRA Subsection 4.3.3 Response to RAI 4.3-3 (FPL letter L-2002-222)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A1)	Implementation Schedule	Source
21	Implement all reasonable alternative inspection/evaluation methods that may be required by the NRC, as appropriate, as conditions for approval of the relief request. Subsequent to the disposition of the relief request and prior to the period of extended operation, the TLAAs for the St. Lucie Units 1 and 2 half-nozzle replacement designs will be dispositioned pursuant to 10 CFR 54.21(c)(1). These TLAAs shall address: 1) the potential growth of the original flaw due to thermal or mechanical cycling, and 2) the potential wastage of the ferritic material that is adjacent to the half-nozzle configuration and exposed to borated reactor coolant. If acceptability of the St. Lucie Units 1 and 2 half-nozzle designs cannot be demonstrated for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(i) or 54.21(c)(1)(ii), then these TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) which may include appropriate nozzle replacement to comply with ASME Section III and ASME Section XI replacement criteria..	Section 18.3.8 of Appendix A1 for St. Lucie Unit 1	Prior to entering the license renewal period for each unit.	LRA Subsection 4.6.4 Responses to RAIs 4.6.4-1, 4.6.4-2, and 4.6.4-3, and Open Item 4.6.4-1. (FPL Letter L-2003-096)

Table 2 - License Renewal Commitment Listing for St. Lucie Unit 2

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
1	Perform inspections on the surfaces of piping and components to determine if galvanic corrosion is active in systems where it is not expected.	18.1.1, Galvanic Corrosion Susceptibility Inspection Program	Prior to the end of the initial operating license term, additional inspections based on results.	LRA Appendix B, Subsection 3.1.2 Response to RAI B.3.1.2-1 (FPL letter L-2002-222)
2	Perform examinations using volumetric techniques of the internal surfaces of stainless steel Auxiliary Feedwater piping downstream of the recirculation orifices and carbon steel Component Cooling Water piping associated with the control room air conditioning.	18.1.2, Pipe Wall Thinning Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.3 Response to RAIs B.3.1.3-1 and B.3.1.3-2 (FPL letter L-2002-166)
3	Submit a report summarizing the aging effects applicable to reactor vessel internals including a description of the inspection plan.	18.1.3, Reactor Vessel Internals Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.4 Response to RAI 3.1-1 (FPL letter L-2002-157)
4	Perform a one-time inspection of the reactor vessel internals	18.1.3, Reactor Vessel Internals Inspection Program	During the period of extended operation.	LRA Appendix B, Subsection 3.1.4

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
5	Submit a report summarizing the inspection plan for small bore Class 1 piping prior to implementation.	18.1.4, Small Bore Class 1 Piping Inspection	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.5 Response to RAI B.3.5-1 (FPL letter L-2002-166)
6	Perform volumetric inspections of a sample of small bore Class 1 piping.	18.1.4, Small Bore Class 1 Piping Inspection	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.5 Response to RAI B.3.5-1 (FPL letter L-2002-166)
7	Implement the Thermal Aging Embrittlement of CASS Program.	18.1.5, Thermal Aging Embrittlement of CASS Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.1.6
8	Perform inspections and examinations of the reactor vessel head, incorporate NRC requirements, FPL responses to NRC IE Bulletins, and industry recommendations including EPRI Materials Reliability Project.	18.2.1, Alloy 600 Inspection Program	On-going.	LRA Appendix B, Subsection 3.2.1 Response to RAI B.3.2.1-1 (FPL letter L-2002-166)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
9	Enhance the ASME Section XI Subsection IWB, IWC, IWD Inservice Inspection Program to: - Perform VT-1 inspections of the core stabilizing lugs and core support lugs, and - Evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue.	18.2.2.1, ASME Section XI Subsection IWB, IWC, IWD Inservice Inspection Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.2.1
10	Expand the scope of the Boric Acid Wastage Surveillance Program to include Waste Management components in the scope of license renewal.	18.2.3, Boric Acid Wastage Surveillance Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.4
11	Revise procedures to provide guidance in the event that fatigue design cycle limits are approached.	18.2.6, Fatigue Monitoring Program	Prior to the end of the initial operating license term.	LRA Appendix B, Subsection 3.2.7
12	Incorporate NFPA-25 testing of wet pipe sprinklers into the Fire Protection Program.	18.2.7, Fire Protection Program	Prior to 50 years from initial operating license.	Response to RAI B.3.2.8-6 (FPL letter L-2002-222)
13	Expand the scope of the Flow Accelerated Corrosion Program to include internal and external loss of material of selected steam traps.	18.2.8, Flow Accelerated Corrosion Program	Prior to the end of the initial operating license term.	LRA Appendix B Subsection 3.2.9

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
14	Enhance the Periodic Surveillance and Preventive Maintenance Program to include components such as filter housings, radiator fins, flexible hoses, door seals, and expansion joints.	18.2.10, Periodic Surveillance and Preventive Maintenance Program	Prior to the end of the initial operating license term.	LRA Appendix B Subsection 3.2.11
15	Program documentation will be enhanced to integrate all aspects of the four subprograms that makeup Reactor Vessel Integrity Program.	18.2.11, Reactor Vessel Integrity Program	Prior to the end of the initial operating license term.	LRA Appendix B Subsection 3.2.12
16	Enhance the Systems and Structures Monitoring Program to include: - Monitoring of the interior surfaces of below groundwater concrete, and examination of a representative sample of below groundwater concrete, when excavated for any reason, - Aging management of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion, and - Aging management of accessible reinforced concrete and reinforced masonry block walls.	18.2.14, Systems and Structures Monitoring Program	Prior to the end of the initial operating license term.	LRA Appendix B Subsection 3.2.14 Response to RAIs 3.5-9 and 3.5-10 (FPL letter L-2002-157) Response to RAI B.3.2.14-2 (FPL letter L-2002-166) Response to RAI 3.5-12 (FPL Letter L-2002-241)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
17	Establish an aging management program to address non-EQ cables and connections in the Containment. The non-EQ cables and connections managed by this program will include those associated with sensitive, low-level signal circuits (source, intermediate, and power range neutron detectors). Complete the first inspection described in the aging management program.	New section to be added	Prior to the end of the initial operating license term.	Response to RAIs 3.6-1 and 3.6-2 (FPL letter L-2002-222)
18	Address environmentally assisted fatigue of the pressurizer surge line using one or more of the following approaches: - Further refinement of the fatigue analysis to lower the CUF(s) to below 1.0, or - Repair of the affected locations, or - Replacement of the affected locations, or Manage the effects of fatigue by an NRC approved inspection program.	18.3.2.3, Environmentally Assisted Fatigue	Prior to the period of extended operation.	LRA Subsection 4.3.3 Response to RAI 4.3-3 (FPL letter L-2002-222)

Item	Commitment	UFSAR Supplement Location (LRA Appendix A2)	Implementation Schedule	Source
19	Implement all reasonable alternative inspection/evaluation methods that may be required by the NRC, as appropriate, as conditions for approval of the relief request. Subsequent to the disposition of the relief request and prior to the period of extended operation, the TLAAs for the St. Lucie Units 1 and 2 half-nozzle replacement designs will be dispositioned pursuant to 10 CFR 54.21(c)(1). These TLAAs shall address: 1) the potential growth of the original flaw due to thermal or mechanical cycling, and 2) the potential wastage of the ferritic material that is adjacent to the half-nozzle configuration and exposed to borated reactor coolant. If acceptability of the St. Lucie Units 1 and 2 half-nozzle designs cannot be demonstrated for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(i) or 54.21(c)(1)(ii), then these TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) which may include appropriate nozzle replacement to comply with ASME Section III and ASME Section XI replacement criteria.	Section 18.3.7 of Appendix A2 for St. Lucie Unit 2	Prior to entering the license renewal period for each unit.	LRA Subsection 4.6.4 Responses to RAIs 4.6.4-1, 4.6.4-2, and 4.6.4-3, and Open Item 4.6.4-1. (FPL Letter L-2003-096)

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10. SUPPLEMENTARY NOTES

Docket Numbers 50-335 and 50-389

11. ABSTRACT *(200 words or less)*

This document is a safety evaluation report regarding the application to renew the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2, which the Florida Power and Light Company filed by letter dated November 29, 2001, and the U.S. Nuclear Regulatory Commission (NRC) received on November 30, 2001. The NRC Office of Nuclear Reactor Regulation has reviewed the license renewal application for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

In its submittal of November 29, 2001, the Florida Power and Light Company requested renewal of the operating licenses for St. Lucie Nuclear Plant, Units 1 and 2 (License Numbers DPR-67 and NFP-16, respectively), which were issued under Section 104b of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current license expiration dates of March 1, 2016, and April 6, 2023, respectively. Units 1 and 2 of the St. Lucie Nuclear Plant are located on Hutchinson Island in St. Lucie County, Florida. Each unit consists of a Combustion Engineering pressurized-water reactor nuclear steam supply system designed to produce a core thermal power output of 2,700 megawatts or approximately 890 megawatts electric.

The NRC license renewal project manager for St. Lucie Nuclear Plant, Units 1 and 2, is Noel Dudley. Mr. Dudley may be contacted by calling 301-415-1154 or by writing to the License Renewal and Environmental Impacts Program, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	13. AVAILABILITY STATEMENT: unlimited
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