PREFACE

The following discussion describes the content of the St. Lucie Units 1 and 2 License Renewal Application.

Chapter 1 provides the administrative information required by Part 54 of Title 10 of the Code of Federal Regulations, Sections 17 and 19 (10 CFR 54.17 and 10 CFR 54.19).

Chapter 2 provides the scoping and screening methodology. Chapter 2 describes and justifies the methodology used to determine the systems, structures, and components within the scope of license renewal and the structures and components subject to an aging management review. Tables 2.2-1, 2.2-2, and 2.2-3 provide listings of the plant mechanical systems, structures, and electrical/instrumentation controls (I&C) systems, respectively, and these tables identify those plant systems and structures that are within the scope of license renewal. Chapter 2 provides a description of systems, intended functions, and references to system boundary drawings. Tables 2.3-1, 2.3-2, 2.3-3, and 2.3-4 show the drawing numbers for the mechanical systems in the scope of license renewal. The drawings are provided in a separate submittal. Tables in Chapter 3 are referenced in Chapter 2.

Chapter 3 describes the results of the aging management reviews for the components and structures requiring aging management reviews. Furthermore, Chapter 3:

- identifies the components and structures subject to aging management review and their intended functions, including a comparison to the structures and components identified in the U. S. Nuclear Regulatory Commision's (NRC's) "Generic Aging Lessons Learned (GALL) Report," NUREG-1801;
- describes or references the processes used to identify aging effects requiring management (Appendix C summarizes the process used to identify aging effects associated with non-Class 1 components, which encompasses engineered safety features system components, auxiliary system components, steam and power conversion system components, and steel in fluid structural components);
- discusses the materials and environments that produce aging effects, including a comparison to the materials and environments identified in the GALL Report for the corresponding components and commodity groups;
- identifies the aging effects requiring management;
- describes industry and plant-specific operating experiences with respect to the applicable aging effects; and
- identifies the aging management programs that will manage the aging effects requiring management.

The aging management programs and the information necessary to demonstrate that the aging effects requiring management will be adequately managed are described in Appendix B. The tables in Chapter 3 provide a comprehensive summary of information concerning the aging effects requiring management for component and commodity groupings in the scope of license renewal. For the component and commodity groupings that make up the system or structure, the tables list intended functions, materials, environments, aging effects, and the aging management programs and activities. Where St. Lucie Units 1 and 2 components/commodities, materials, and environments are all consistent with the GALL Report, a reference to the appropriate section of the GALL Report is identified in the tables.

Chapter 4 includes a list of time-limited aging analyses (TLAAs), as defined by 10 CFR 54.3. It includes the identification of the component or subject, and an explanation of the time-dependent aspects of the calculation or analysis. Chapter 4 demonstrates that the analyses remain valid for the period of extended operation, the analyses have been projected to the end of the period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Chapter 4 also states that no 10 CFR 50.12 exemption involving a time-limited aging analysis as defined in 10 CFR 54.3 is required during the period of extended operation.

Appendix A, Updated Final Safety Analysis Report Supplements, contains two distinct subsections: Appendix A1 for St. Lucie Unit 1 and Appendix A2 for St. Lucie Unit 2. Each subsection provides a summary description of the programs for managing the effects of aging for the period of extended operation. A summary description of the evaluation of time-limited aging analyses for the period of extended operation is also included for each unit.

Appendix B, Aging Management Programs, describes the aging management programs and activities and demonstrates that the aging effects on the components and structures within the scope of the License Renewal Rule will be managed such that they will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. Where the St. Lucie Units 1 and 2 programs are consistent with corresponding programs in the GALL Report, the appropriate GALL program is referenced. The St. Lucie Units 1 and 2 programs and activities that are credited for managing the effects of aging are divided into new actions and existing actions.

Appendix C, Process for Identifying Aging Effects Requiring Management for Non-Class 1 Components, summarizes the process through which the applicable aging effects were identified and associated with the non-Class 1 components determined to be subject to an aging management review.

Appendix D, Technical Specification Changes, concludes that no technical specification changes are necessary to manage the effects of aging during the period of extended operation.

The information in Chapter 2, Chapter 3, and Appendix B fulfills the requirements in 10 CFR 54.21(a). Section 1.4 discusses how the requirements of 10 CFR 54.21(b) will be met. The information in Chapter 4 fulfills the requirements in 10 CFR 54.21(c). The information in Appendix A and Appendix D fulfills the requirements in 10 CFR 54.21(d) and 10 CFR 54.22, respectively. The supplement to the Environmental Report, as required by 10 CFR 54.23, is provided with the St. Lucie Units 1 and 2 License Renewal Application as a separate document.

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APPENDICES

LIST OF TABLES

1.0 ADMINISTRATIVE INFORMATION

1.1 PURPOSE AND GENERAL INFORMATION

Pursuant to Part 54 of Title 10 of the Code of Federal Regulations (10 CFR 54), this Application seeks renewal for an additional 20-year term of the facility operating licenses for St. Lucie Unit 1 (DPR-67) and Unit 2 (NPF-16). The Unit 1 operating license (DPR-67) currently expires at midnight, March 1, 2016. The Unit 2 operating license (NPF-16) expires at midnight, April 6, 2023. The application includes renewal of the source, special nuclear, and byproduct materials licenses that are combined in the Unit 1 and Unit 2 licenses.

The application is organized in accordance with U. S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Licenses," dated July 2001, which endorses the guidance provided by NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, dated March 2001.

Section 54.17(c) of 10 CFR 54 requires that an application for a renewed operating license not be submitted earlier than 20 years before the expiration of the license currently in effect. This application is being submitted earlier than 20 years before the expiration of the current operating license for St. Lucie Unit 2; however, an exemption to the 20-year requirement of 10 CFR 54.17(c) was approved by the NRC as documented in the NRC letter and Safety Evaluation dated February 27, 2001 (TAC No. MB0418). St. Lucie Unit 1 does not require such an exemption.

The environmental information required by 10 CFR 54.23 is provided as a separate report entitled, "Applicant's Environmental Report – Operating License Renewal Stage, St. Lucie Units 1 & 2."

This License Renewal Application and its supporting Environmental Report are intended to provide sufficient information for the NRC to complete its technical and environmental reviews. The License Renewal Application and Environmental Report are designed to allow the NRC to make the finding required by 10 CFR 54.29 in support of the issuance of renewed operating licenses for St. Lucie Units 1 and 2. Following is the general information required by 10 CFR 54.17 and 10 CFR 54.19.

1.1.1 NAME OF APPLICANT

Florida Power & Light Company

[St. Lucie Unit 2 is owned, in part, by the Orlando Utilities Commission of the City of Orlando, Florida (≈6.1%), and the Florida Municipal Power Agency (≈8.8%). However, Florida Power & Light Company is the majority owner (≈85.1%) and is authorized to act as agent for the Orlando Utilities Commission and the Florida Municipal Power Agency and has exclusive responsibility and control over the physical construction, operation, and maintenance of the facility. St. Lucie Unit 1 is wholly owned and operated by Florida Power & Light Company.]

1.1.2 ADDRESS OF APPLICANT

Florida Power & Light Company
700 Universe Boulevard
Post Office Box 14000
Juno Beach, Florida 33408-0420

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801-4408

Address of the St. Lucie Nuclear Plant:

Florida Power & Light Company
St. Lucie Nuclear Plant
6351 S. Ocean Drive
Jensen Beach, Florida 34957-2000

1.1.3 OCCUPATION OF APPLICANT

Florida Power & Light Company (FPL) is an investor-owned utility, primarily engaged in the generation, transmission, and distribution of electricity. The service territory covers the southern third and almost the entire eastern seaboard of the State of Florida. FPL supplies electric service to more than 3.7 million residential, commercial, and industrial customers. To service this area, FPL operates 14 electric generating facilities with an installed capacity of over 16,000 megawatts (MW) electric, including the St. Lucie Nuclear Plant.

Florida Municipal Power Agency (FMPA) is a nonprofit, joint action agency formed by twenty-nine (29) municipal electric utilities, serving approximately 700,000 customers in the State of Florida.

Orlando Utilities Commission (OUC) is a municipally owned public utility providing water and electric service to the City of Orlando and adjoining portions of Orange County. OUC currently serves 156,000 customers in the entire City of Orlando, a portion of unincorporated Orange County, and the City of St. Cloud.

1.1.4 ORGANIZATION AND MANAGEMENT OF APPLICANT

FPL is a public utility incorporated under the laws of the State of Florida, with its principal office located in Juno Beach, Florida.

FPL is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The names and business addresses of FPL's, FMPA's, and OUC's directors and principal officers are listed below. All persons listed are U.S. citizens.

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1.1.5 CLASS AND PERIOD OF LICENSE SOUGHT

FPL requests renewal of the Class 104b operating license for St. Lucie Unit 1 and the Class 103 operating license for St. Lucie Unit 2 (license numbers DPR-67 and NPF-16, respectively) for a period of 20 years beyond the expiration of the current licenses. For St. Lucie Unit 1 (DPR-67), license renewal would extend the licensed term from midnight March 1, 2016, until midnight March 1, 2036. For St. Lucie Unit 2 (NPF-16), license renewal would extend the licensed term from midnight April 6, 2023, until midnight April 6, 2043. This application also seeks renewal of those NRC source material, special nuclear material, and byproduct material licenses that are currently subsumed into or combined with the current operating licenses.

The facility will continue to be known as the St. Lucie Nuclear Plant and will continue to generate electric power during the renewal period.

1.1.6 ALTERATION SCHEDULE

FPL does not propose to construct or alter any production or utilization facility in connection with this renewal application.

1.1.7 REGULATORY AGENCIES

The Florida Public Service Commission and the Federal Energy Regulatory Commission have jurisdiction over FPL's rates and services.

Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426-0002

1.1.8 NEWS PUBLICATIONS

The following news publications are in circulation near the St. Lucie plant and are considered appropriate to give reasonable notice of this application:

The Tribune
600 Edwards Road
Fort Pierce, Florida 34982-6295
561-461-2050
Fax-561-461-4447

Okeechobee News
107 SW 17th Street, Suite D
Okeechobee, Florida 34974-6110
941-763-3134
Fax-941-763-5901

The Stuart News
1939 SE Federal Highway
Stuart, Florida 34994-3915
561-287-1550
Fax-561-221-4246

The Port St. Lucie News
1932 SE Port St. Lucie Blvd.
Port St. Lucie, Florida 34952-5509
561-337-5800
Fax-561-335-0877

Vero Beach Press Journal
1801 US Highway 1
Vero Beach, Florida 32960-0997
561-562-2315
Fax-561-978-2364

The Palm Beach Post
2751 South Dixie Highway
West Palm Beach, Florida 33405-1298
561-820-4100
Fax-561-820-4407

1.1.9 CONFORMING CHANGES TO THE STANDARD INDEMNITY AGREEMENT

The requirements at 10 CFR 54.19(b) state that license renewal applications 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 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 conforming changes be made to Item 3 of the Attachment, and to any other sections of the indemnity agreement as appropriate.

1.1.10 RESTRICTED DATA AGREEMENT

This application does not contain any Restricted Data or National Security Information, and FPL does not expect that any activity under the renewed licenses for St. Lucie Units 1 and 2 will involve such information. However, if such information were to become involved, FPL agrees that it would appropriately safeguard such information and would not permit any individual to have access to, or any facility to possess, such information until the individual or facility had been approved under the provisions of 10 CFR 25 or 10 CFR 95, respectively.

1.2 DESCRIPTION OF ST. LUCIE NUCLEAR PLANT

The St. Lucie Nuclear Plant is a steam electric generating facility situated on the East Coast of Florida, about 7 miles southeast of the city of Fort Pierce, Florida. The plant consists of two nuclear power units designated as St. Lucie Unit 1 and St. Lucie Unit 2.

The St. Lucie Units 1 and 2 reactors are Combustion Engineering designed pressurized light-water moderated and cooled systems. Each reactor is designed to produce a core thermal power output of 2700 megawatts thermal (MWt). Each steam and power conversion system, including its turbine generator, is designed to permit generation of a net electrical output of approximately 890 MW. St. Lucie Units 1 and 2 were each originally licensed and operated at 2560 MWt; however, both Units' operating licenses were subsequently amended to allow operation at the stretch power limit of 2700 MWt (Unit 1 Amendment #48 dated November 23, 1981; Unit 2 Amendment #9 dated March 1, 1985).

Descriptions of St. Lucie Units 1 and 2 systems and structures can be found in the Updated Final Safety Analysis Report (UFSAR) for each Unit. Additional descriptive information about St. Lucie Units 1 and 2 systems, structures, and components is provided in Chapters 2, 3, and 4 of this application, and references to the UFSARs are provided where pertinent.

1.3 TECHNICAL INFORMATION REQUIRED FOR AN APPLICATION

In accordance with 10 CFR 54.21, four technical items are required to support an application for a renewed operating license. These are an integrated plant assessment (Chapters 2 and 3), an evaluation of time-limited aging analyses (Chapter 4), a supplement to the St. Lucie Units 1 and 2 UFSARs that contains a summary description of the programs and activities for managing the effects of aging and the evaluation of the time-limited aging analyses (Appendix A), and current licensing basis changes during NRC review (Section 1.4).

In addition to the technical information, 10 CFR 54.22 requires applicants to submit any Technical Specification changes or additions necessary to manage the effects of aging during the period of extended operation (Appendix D). Also, 10 CFR 54.23 requires the application to include a supplement to the Environmental Report (Applicant's Environmental Report – Operating License Renewal Stage).

The Integrated Plant Assessment (IPA), as defined by 10 CFR 54.3, is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with 10 CFR 54.21(a) for license renewal have been identified. The IPA also demonstrates that the effects of aging on the functionality of such structures and components will be managed to maintain the current licensing basis during the period of extended operation. The St. Lucie Units 1 and 2 IPA includes:

- identification of the structures and components within the scope of license renewal that are subject to an aging management review;
- identification of the aging effects applicable to these structures and components;
- identification of plant-specific programs and activities that will manage these identified aging effects; and
- a demonstration that these programs and activities will be effective in managing the effects of aging during the period of extended operation.

The St. Lucie Units 1 and 2 IPA for license renewal, along with other information necessary to document compliance with 10 CFR 54, is maintained in an auditable and retrievable form in accordance with 10 CFR 54.37(a). The St. Lucie Units 1 and 2 IPA is documented with site-specific reports and calculations that were generated in accordance with FPL's Quality Assurance Program. Also, note that references to the St. Lucie Units 1 and 2 Technical Specifications are as of Amendments 177/120, respectively, and references to the St. Lucie Units 1 and 2 UFSARs are as of Amendments 18/13, respectively.

1.4 CURRENT LICENSING BASIS CHANGES DURING NRC REVIEW

Each year, following the submittal of the St. Lucie Units 1 and 2 License Renewal Application and at least three months before the scheduled completion of the NRC review, FPL will submit amendments to the application pursuant to 10 CFR 54.21(b). These revisions will identify any changes to the current licensing basis that materially affect the contents of the License Renewal Application, including the UFSAR supplements and any other aspects of the application.

2.0 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

This chapter describes the process for the identification of structures and components subject to an aging management review in the St. Lucie integrated plant assessment (IPA). For those systems, structures, and components (SSCs) within the scope of license renewal, 10 CFR 54.21(a)(1) requires a license renewal applicant to identify and list the structures and components subject to an aging management review. Furthermore, 10 CFR 54.21(a)(2) requires that methods used to identify and list these structures and components be described and justified. The technical information in this chapter serves to satisfy these requirements.

St. Lucie's IPA methodology follows the approach recommended in NEI 95-10 [Reference 2.1-1]. The methodology consists of scoping, screening, and aging management reviews. The methodology is implemented in accordance with FPL's Quality Assurance Program.

The scoping and screening methodology is described in Section 2.1. The results of the assessment to identify the systems and structures within the scope of license renewal (plant level scoping) are contained in Section 2.2. The results of the identification of the components and structural components subject to an aging management review (screening) are contained in Section 2.3 for mechanical systems, Section 2.4 for structures, and Section 2.5 for electrical/I&C systems.

2.1 SCOPING AND SCREENING METHODOLOGY

Scoping is the evaluation performed to identify SSCs that satisfy the criteria in 10 CFR 54.4. Based on the nature and content of design information systems at St. Lucie Nuclear Plant, scoping as defined in 10 CFR 54.4 was performed in two steps: (1) plant level scoping, and (2) component and structural component scoping. For the first step, an evaluation was performed to identify systems and structures that satisfy the criteria in 10 CFR 54.4. This is designated as plant level scoping and is described in Subsection 2.1.1. For the second step, the systems and major structures identified as satisfying the criteria in 10 CFR 54.4 were further evaluated to identify the specific components and structural components that satisfy the criteria in 10 CFR 54.4 and, therefore, are in the scope of license renewal.

Once the in-scope components and structural components were identified, they were screened to identify those subject to an aging management review in accordance with 10 CFR 54.21(a)(1). The component and structural component scoping and screening process is described in Subsection 2.1.2.

The scoping and screening methodology utilized for St. Lucie Units 1 and 2 license renewal is the same as the methodology FPL employed for Turkey Point Units 3 and 4.

2.1.1 PLANT LEVEL SCOPING

Plant level scoping begins by defining the plant in terms of major systems and structures. These systems and structures are then evaluated against the scoping criteria in 10 CFR 54.4.

Specifically, 10 CFR 54.4 states that:

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components 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 functions-

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) 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.

(2) All non-safety related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

(3) 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 fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

(b) The intended functions that these systems, structures, and components must be shown to fulfill in 10 CFR 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section.

The scoping process to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) is performed on systems and structures using documents that form the Current Licensing Bases (CLBs) and other information sources. The CLBs for St. Lucie Units 1 and 2 have been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLBs include the UFSARs, Technical Specifications, and docketed licensing correspondence. Other important information sources used for scoping are further described in Subsection 2.1.1.1.

The aspects of the scoping process used to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) are described in Subsections 2.1.1.2, 2.1.1.3, and 2.1.1.4, respectively.

2.1.1.1 INFORMATION SOURCES

In addition to the UFSARs, Technical Specifications, and docketed licensing correspondence, three information sources - the design basis documents (DBDs), the component database, and piping and instrumentation diagrams (P&IDs) - were relied upon to a great extent in performing scoping and screening for St. Lucie Units 1 and 2. A brief discussion of these sources is provided.

2.1.1.1.1 DESIGN BASIS DOCUMENTS

Prior to 1991, St. Lucie Units 1 and 2 participated in a Combustion Engineering Owners Group project to develop a computerized database of design basis references for the plant systems supplied by Combustion Engineering. This project is referred to as the Design Basis Reference System (DBRS). During development of the DBRS, FPL management determined that there was a need to develop the DBDs to provide consolidated and verified design basis information in addition to the DBRS.

DBDs are a tool to explain the requirements behind the design rather than describing the design itself. DBDs are intended to complement other upper-tier documents such as the UFSAR and Technical Specification Bases. Twenty-one DBD volumes were developed for each St. Lucie Unit. This included DBDs for twenty support and accident mitigation systems and one DBD on selected licensing issues. The Selected Licensing Issues DBD provides a plant-specific discussion of selected licensing issues.

2.1.1.1.2 COMPONENT DATABASE

Specific component information for SSCs at St. Lucie Units 1 and 2 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.

2.1.1.1.3 P&IDs

P&IDs are schematic-type drawings that have been created for every significant plant piping system and several ventilation systems. 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 described in Unit 1 UFSAR Chapter 3 and Unit 2 UFSAR Chapter 3. Water and steam containing components are designated Quality Group A, B, C, or D in accordance with their importance to safety. This importance, as emphasized by quality group assignment, is considered in design, material, fabrication, assembly, construction, and operation of the component. A single system may have components in more than one quality group. Quality group designations are provided in Unit 1 UFSAR Table 3.2-1 and Unit 2 UFSAR Table 3.2-1. Corresponding minimum design code requirements applied to the various components in each quality group are given in Unit 1 UFSAR Table 3.2-2 and Unit 2 UFSAR Table 3.2-2.

2.1.1.2 SAFETY-RELATED CRITERIA PURSUANT TO 10 CFR 54.4(a)(1)

10 CFR 54.4(a)(1) states that SSCs within the scope of license renewal include safety-related SSCs that are relied upon to remain functional during and following design basis events [as defined in 10 CFR 50.49(b)(1)] to ensure the following functions:

- the integrity of the reactor coolant pressure boundary;
- the capability to shut down the reactor and maintain it in a safe shutdown condition; or
- 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 St. Lucie Nuclear Plant has not revised its current accident source term, therefore, 10 CFR 50.67 is not applicable to this License Renewal Application.

St. Lucie Units 1 and 2 established safety classifications for systems and structures at the component level consistent with the definition of safety-related SSCs provided in the FPL Quality Assurance Program and the St. Lucie Units 1 and 2 CLBs. FPL's definition of "safety related" encompasses the definition of "safety related" specified in 10 CFR 54.4(a)(1).

Safety classifications of SSCs were included in the component database and were established based on reliance on the SSCs during and following design basis events, which include design basis accidents, anticipated operational occurrences, natural phenomena, and external events. The design basis events considered are consistent with the St. Lucie Units 1 and 2 CLBs. Unit 1 UFSAR Chapter 15 and Unit 2 UFSAR Chapter 15 provide the design basis event accident analyses for St. Lucie Nuclear Plant.

Natural phenomena and external events are described in Unit 1 UFSAR Chapter 2 and Unit 2 UFSAR Chapter 2 and in appropriate sections of the design basis documents. Structures designed to withstand design basis events, natural phenomena, and external events are described in Unit 1 UFSAR Chapter 3 and Unit 2 UFSAR Chapter 3.

Certain design basis events - waste gas decay tank leakage/rupture event (Unit 1 UFSAR Section 15.4.2), fuel handling accident (Unit 1 UFSAR Section 15.4.3), and radioactive releases from a subsystem or component (Unit 2 UFSAR Section 15.7) - require further discussion relative to the scoping criteria in 10 CFR 54. Note, the radioactive releases included in Unit 2 UFSAR Section 15.7 include radioactive liquid waste system leak or failure, waste gas decay tank failure, spent fuel cask drop, and fuel handling accident. These design basis events are related only to offsite radiological consequences and do not involve analyses related to the reactor coolant pressure boundary, or the capability to shut down the reactor and maintain it in a safe shutdown condition. Table 2.1-1 of this application provides the radiological consequences of these design basis events. The offsite dose analyses indicate that the radiological consequences of these design basis events, except for the Unit 2 fuel handling accident, represent a small fraction of the 10 CFR Part 100 limits. As a result, SSCs related to the prevention and/or mitigation of these design basis events do not meet the scoping criteria of 10 CFR 54.4(a)(1)(iii). This equipment will still be evaluated relative to the scoping criteria of 10 CFR 54.4 (a)(2) and 10 CFR 54.4 (a)(3).

The steps to identify systems and structures at St. Lucie Units 1 and 2 that meet the criteria of 10 CFR 54.4(a)(1) are outlined below:

- The UFSARs, licensing correspondence, design basis documents, component database, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criteria of 10 CFR 54.4(a)(1) were identified for each system and structure determined to be safety related.

The scoping process to identify safety-related systems and structures for St. Lucie Units 1 and 2 is consistent with and satisfies the criteria in 10 CFR 54.4(a)(1).

2.1.1.3 NON-SAFETY RELATED CRITERIA PURSUANT TO 10 CFR 54.4(a)(2)

10 CFR 54.4(a)(2) states that SSCs within the scope of license renewal include non-safety related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified for safety-related SSCs.

The non-safety related SSCs that are within the scope of license renewal for St. Lucie Units 1 and 2 fall into two categories:

- Non-safety related SSCs that functionally support the operation of safety-related SSCs, and
- 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).

The only non-safety related SSCs that functionally support the operation of safety-related SSCs at St. Lucie Units 1 and 2 are non-safety related piping segments that provide structural support at safety-related/non-safety related boundaries. The safety-related/non-safety related functional boundaries for piping systems are typically made at system pressure boundary valves. However, the seismic integrity boundary may extend beyond the system pressure boundary valve. The seismic integrity support system includes the piping segments and supports that provide structural support for the boundary valve. These components ensure the integrity of the safety-related/non-safety related functional system pressure boundary under design basis loading conditions. As such, the non-safety related piping and supports beyond the safety-related/non-safety related boundary are conservatively assumed to meet the scoping criteria of 10 CFR 54.4(a)(2).

The second category involves the potential for non-safety related systems or structures to impact the ability of safety-related systems or structures to perform their intended functions. To complete this portion of the scoping effort, a systematic review of potential non-safety related/safety-related interactions was performed. These interactions include high-energy pipe breaks, moderate-energy pipe breaks, and interaction of seismically supported non-safety related systems with safety-related SSCs.

With regard to pipe breaks due to assumed failures of non-safety related piping, FPL performed reviews for jet impingement, reactive forces and pipe whip, compartment pressurization and environmental effects for high-energy (i.e., fluid systems that exceed 200°F or 275 psig during normal operating conditions) pipe breaks, and wetting and flooding effects for moderate-energy (i.e., fluid systems that are 200°F or less, and 275 psig or less during normal operating conditions) pipe breaks. Since failure of the non-safety related piping is assumed in these evaluations, the piping does not fall within the scope of license renewal. However, the design features required to accommodate the effects of the pipe break, for example, pipe whip restraints, internal barriers, curbing, platforms, sumps, and sump pumps, are included in the scope of license renewal. See Unit 1 UFSAR Sections 3.6 and 9.5a and Unit 2 UFSAR Section 3.6 for additional discussion.

In the case of "seismic II over I," or the potential for non-safety related SSCs to fall 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 are included within the scope of license renewal. This review also concluded, however, that the non-safety related piping does not fall within the scope of license renewal. Empirical evidence documented in a NRC-endorsed Electric Power Research Institute (EPRI) report (EPRI NP-6041-SL), a NUREG (NUREG CR-6239), and the conclusion of an industry expert on seismic design determined the following:

- No experience data exist of welded steel pipe segments falling due to a strong motion earthquake;
- Falling of a piping system is extremely rare and only occurs when there is a failure or unzipping of the supports; and
- These observations apply to new or aged pipe.

Thus, "seismic II over I" piping segments do not perform an intended function defined by 10 CFR 54.4(a)(2), and therefore are not within the scope of license renewal. However, some non-safety related piping segments have been designed and built to Category I (seismic) requirements to preclude the potential for flooding or wetting spray in certain plant areas. In these instances, the seismic non-safety related piping and supports are both included within the license renewal boundary.

For seismic interactions, FPL has chosen a component/spaces approach to scoping, because the seismic interaction design feature is dependent upon the location of the non-safety related system or structure relative to safety-related systems and structures. The approach utilized identifies the major structures of the plant containing both safety-related and non-safety related systems and structures. Component and structural component level scoping performed as part of the screening process (see Subsection 2.1.2.2) then established the specific non-safety related seismic interaction component/structural component types located within these structures for inclusion in the license renewal scope. Based on this approach, non-safety related components and structural components with the potential for seismic interactions are identified as in the scope of license renewal.

The steps to identify non-safety related systems and structures at St. Lucie Nuclear Plant that meet the criteria of 10 CFR 54.4(a)(2) are outlined below:

- The UFSARs, licensing correspondence, design basis documents, component database, pipe stress analyses, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criteria of 10 CFR 54.4(a)(2) were identified for in-scope SSCs determined to be non-safety related whose failure could affect safety-related SSCs.

The scoping process to identify non-safety related systems and structures whose failure can affect safety-related systems and structures for St. Lucie Units 1 and 2 is consistent with and satisfies the criteria in 10 CFR 54.4(a)(2).

2.1.1.4 OTHER SCOPING PURSUANT TO 10 CFR 54.4(a)(3)

10 CFR 54.4(a)(3) states that SSCs within the scope of license renewal include all systems and structures relied on in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

Scoping based on each of these regulations is described in the following sections.

2.1.1.4.1 FIRE PROTECTION (FP)

Fire protection features and commitments are described in detail in Unit 1 UFSAR Appendix 9.5A and Unit 2 UFSAR Appendix 9.5A. The systems and structures at St. Lucie Nuclear Plant that support the multiple levels of protection for postulated fires are considered within the scope of license renewal. At St. Lucie Nuclear Plant, non-safety related SSCs relied on for fire protection typically carry an augmented quality classification (Quality Related) and are included in the FPL Quality Assurance Program.

In addition to the St. Lucie Units 1 and 2 UFSARs and licensing correspondence, two primary information sources utilized in performing this portion of the scoping effort were the St. Lucie Essential Equipment Lists and the Safe Shutdown Analyses.

With regard to the Safe Shutdown Analyses, Section III.G.1 of Appendix R to 10 CFR 50 requires that FP features be provided for systems, structures, and components important to safe shutdown. In order to meet these requirements, all equipment required for safe shutdown, including the associated power and control cables, and any equipment that could adversely affect safe shutdown if spuriously actuated by fire-induced faults, have been identified for every fire area in the plant in order to assess the FP required. Utilizing this information, Safe Shutdown Analyses were performed to determine the impact of a postulated fire on the safe-shutdown equipment and circuitry within each fire area. These analyses ensured that no single fire could prevent St. Lucie Unit 1 or 2 from achieving a safe cold shutdown.

The Safe Shutdown Analyses provide the results of detailed design reviews utilizing the fire hazards analysis concept. These fire hazards analyses postulated a worst-case "exposure fire," composed of in situ combustibles, and the resulting fire hazard was analyzed in each critical plant area; i.e., those areas of the plant wherein a fire could conceivably impair safe shutdown. To perform these fire hazards analyses, a list of the minimum essential equipment required for hot standby, cooldown, and cold shutdown was prepared for each unit. These lists are the Essential Equipment Lists. One feature of St. Lucie's Essential Equipment Lists is that no equipment in storage is credited for safe shutdown.

The steps to identify systems and structures relied upon for FP at St. Lucie Nuclear Plant that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, Essential Equipment Lists, Safe Shutdown Analyses, licensing correspondence, design basis documents, component database, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for FP were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for FP for St. Lucie Units 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.1.4.2 ENVIRONMENTAL QUALIFICATION (EQ)

Certain safety-related electrical components are required to withstand environmental conditions that may occur during or following a design basis accident per 10 CFR 50.49. The criteria for determining which equipment requires EQ are identified on the St. Lucie Units 1 and 2 Environmental Qualification Lists for 10 CFR 50.49. TLAAs associated with EQ equipment are discussed in Subsection 4.4.1.

For non-safety related electrical components whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, FPL elected not to differentiate between safety-related and non-safety related components. If failure of an electrical component can affect safety-related functions, that electrical component is treated as safety-related for EQ purposes.

The steps to identify systems and structures subject to EQ at St. Lucie Units 1 and 2 that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, licensing correspondence, Environmental Qualification Lists, and design basis documents were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for EQ were identified for each plant system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for EQ for St. Lucie Units 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.1.4.3 PRESSURIZED THERMAL SHOCK (PTS)

"Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," (10 CFR 50.61) requires that licensees evaluate the reactor vessel beltline materials against specific criteria to ensure protection against brittle fracture. See References 2.1-2 through 2.1-11 for a listing of St. Lucie Units 1 and 2 licensing correspondence related to PTS.

The steps to identify systems and structures relied upon for protection against PTS at St. Lucie Units 1 and 2 that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, licensing correspondence, design basis documents, component database, and design drawings were reviewed, as applicable.
- Based on the above, the only components relied upon for protection against PTS are the reactor vessels (see Subsection 4.2.1).

The scoping process to identify systems and structures relied upon and/or specifically committed to for PTS for St. Lucie Units 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.1.4.4 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS)

St. Lucie Units 1 and 2 design features related to ATWS events are described in detail in Unit 1 UFSAR Section 7.6.1.4 and Unit 2 UFSAR Section 7.6.3.6. See References 2.1-12 through 2.1-20 for a listing of St. Lucie Units 1 and 2 licensing correspondence related to ATWS.

The steps to identify systems and structures relied upon for ATWS events at St. Lucie Units 1 and 2 that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, licensing correspondence, design basis documents, component database, and design drawings were reviewed, as applicable.
- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for ATWS events were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for ATWS events for St. Lucie Units 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.1.4.5 STATION BLACKOUT (SBO)

The UFSARs and design basis documents provide the licensing criteria that are the bases for St. Lucie Nuclear Plant's resolution to station blackout. Design features to satisfy the Station Blackout Rule are described in Unit 1 UFSAR Section 15.2.13 and Unit 2 UFSAR Section 15.10. St. Lucie Units 1 and 2 licensing correspondence related to the plants' SBO analyses is listed as References 2.1-21 through 2.1-25.

The steps to identify systems and structures relied upon for SBO events at St. Lucie Nuclear Plants that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The UFSARs, licensing correspondence, design basis documents, component database, and design drawings were reviewed, as applicable.

- Based on the above, license renewal intended functions relative to the criterion of 10 CFR 54.4(a)(3) for SBO events were identified for each system and structure determined to meet this criterion.

The scoping process to identify systems and structures relied upon and/or specifically committed to for SBO events for St. Lucie Units 1 and 2 is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.2 COMPONENT/STRUCTURAL COMPONENT SCOPING AND SCREENING

This subsection discusses the process used at St. Lucie Units 1 and 2 to: (1) identify components and structural components (collectively abbreviated as SCs) within the scope of license renewal for in-scope systems and structures; and (2) identify which of the SCs determined to be in-scope require an aging management review.

The requirement to identify SCs subject to an aging management review is specified in 10 CFR 54.21(a)(1), which states:

Each application must contain the following information:

(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in 10 CFR 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components-

(i) That perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) That are not subject to replacement based on a qualified life or specified time period.

This portion of St. Lucie's IPA methodology is divided into three engineering disciplines: mechanical, civil/structural, and electrical/I&C. The relevant aspects of the SC scoping and screening process for mechanical systems, civil structures, and electrical/I&C systems are described in Subsections 2.1.2.1, 2.1.2.2, and 2.1.2.3, respectively.

For mechanical systems and civil structures, this process establishes evaluation boundaries, determines the SCs that compose the system or structure, determines which of those SCs support system/structure intended functions, and identifies specific SC intended functions. Consequently, not all of the SCs for in-scope systems or structures are in the scope of license renewal. Once these in-scope SCs are identified, the process then determines which SCs are subject to an aging management review per the criteria of 10 CFR 54.21(a)(1).

For electrical/I&C systems, a bounding approach as described in NEI 95-10 [Reference 2.1-1] is taken. This approach establishes evaluation boundaries, determines the electrical/I&C component commodity groups that compose in-scope systems, identifies specific component and commodity intended functions, and then determines which component commodity groups are subject to an aging management review per the criteria of 10 CFR 54.21(a)(1). This approach calls for component scoping after screening has been performed.

2.1.2.1 MECHANICAL SYSTEMS

For mechanical systems, the component/structural component scoping and screening process is performed on each system identified to be within the scope of license renewal. This process evaluates the individual SCs included within in-scope mechanical systems to identify specific SCs or SC groups that require an aging management review.

Mechanical system evaluation boundaries were established for each system within the scope of license renewal. These boundaries were determined by mapping the pressure boundary associated with license renewal system intended functions onto the system flow diagrams. [License renewal system intended functions are the functions a system must perform relative to the scoping criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).] The flow diagram boundary drawings associated with each mechanical system within the scope of license renewal are identified with the mechanical system screening results described in Section 2.3.

The sequence of steps performed on each mechanical system determined to be within the scope of license renewal is as follows:

- Based on a review of design drawings and the system component list from the component database, SCs that are included within the system are identified.
- Based on the plant level scoping results, the pressure boundary associated with license renewal system intended functions is mapped onto the system's 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 identified.
- Component intended functions for in-scope SCs are identified. The component intended functions identified are based on the guidance of NEI 95-10.
- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties [screening criterion of 10 CFR 54.21(a)(1)(i)] are identified. Active/passive screening determinations are 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 [screening criterion of 10 CFR 54.21(a)(1)(ii)] are identified as requiring an aging management review. The determinations of whether passive, in-scope SCs have a qualified life or specified replacement time period are

based on the review of plant-specific information, including the component database, maintenance programs and procedures, vendor manuals, and plant experience.

- The in-scope SCs identified as requiring an aging management review are compared to the GALL Report [Reference 2.1-26] to ensure differences are valid and justified.

2.1.2.2 CIVIL STRUCTURES

For structures, the SC scoping and screening process is performed on each structure identified to be within the scope of license renewal. This method evaluates the individual SCs included within in-scope structures to identify specific SCs or SC groups that require an aging management review.

The sequence of steps performed on each structure determined to be within the scope of license renewal is as follows:

- Based on a review of design drawings, the structure component list from the component database, and plant walkdowns, SCs that are included within the structure are 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 identified.
- Design features and associated SCs that prevent potential seismic interactions for in-scope structures housing both safety-related and non-safety related systems are identified. This includes a walkdown of each plant area containing both safety-related and non-safety related SSCs.
- Component intended functions for in-scope SCs are identified. The component intended functions identified are based on the guidance of NEI 95-10.
- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties [screening criterion of 10 CFR 54.21(a)(1)(i)] are identified. Active/passive screening determinations are 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 [screening criterion of 10 CFR 54.21(a)(1)(ii)] are identified as requiring an aging management review. The determinations of whether passive, in-scope SCs have a qualified life or specified replacement time period are based on the review of plant-specific information, including the component database, maintenance programs and procedures, vendor manuals, and plant experience.
- The in-scope SCs identified as requiring an aging management review are compared to the GALL Report to ensure differences are valid and justified.

2.1.2.3 ELECTRICAL AND I&C SYSTEMS

The method used to determine which electrical/I&C components are subject to an aging management review is organized based on component commodity groups. 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 aging management review. The method employed is consistent with the guidance in NEI 95-10.

The sequence of steps for identification of electrical/I&C components that require an aging management review is as follows:

- Electrical/I&C component commodity groups associated with electrical, I&C, and mechanical systems within the scope of license renewal are identified. This step includes a complete review of design drawings and electrical/I&C component commodity groups in the component database.
- A description and function for each of the electrical/I&C component commodity groups are identified.
- The electrical/I&C component commodity groups that perform an intended function without moving parts or without a change in configuration or properties [screening criterion of 10 CFR 54.21(a)(1)(i)] are identified. Active/passive screening determinations are based on the guidance in Appendix B to NEI 95-10.
- For the passive electrical/I&C component commodity groups, component commodity groups that are not subject to replacement based on a qualified life or specified time period [screening criterion of 10 CFR 54.21(a)(1)(ii)] are identified as requiring an aging management review. Electrical/I&C component commodity groups covered by the St. Lucie 10 CFR 50.49 Environmental Qualification Program are 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 are eliminated.
- The in-scope SCs identified as requiring an aging management review are compared to the GALL Report to ensure differences are valid and justified.

2.1.3 GENERIC SAFETY ISSUES

In accordance with the guidance in NEI 95-10 [Reference 2.1-1] and Appendix A.3 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" [Reference 2.1-27], review of NRC generic safety issues (GSIs) as part of the license renewal process is required to satisfy a finding per 10 CFR 54.29. This guidance suggests that GSIs that involve issues related to license renewal aging management reviews or TLAAs should be addressed in the License Renewal Application. Based on Nuclear Energy Institute (NEI) and NRC guidance, NUREG-0933 [Reference 2.1-28], and previous license renewal applicants, FPL has identified the following GSIs to be addressed for St. Lucie Units 1 and 2:

- GSI 168, Environmental Qualification of Electrical Equipment – This GSI is related to aging concerns with respect to EQ of electrical equipment. Environmental qualification evaluations of electrical equipment are identified as TLAAs for St. Lucie Units 1 and 2. Accordingly, this GSI is addressed in Subsection 4.4.2.
- GSI 190, Fatigue Evaluation of Metal Components for 60-year Plant Life – This GSI addresses fatigue life of metal components and was closed by the NRC [Reference 2.1-29]. In the closure letter, however, the NRC concluded that licensees should address the effects of reactor coolant environment on component fatigue life as aging management programs are formulated in support of license renewal. Accordingly, the issue of environmental effects on component fatigue life is addressed in Subsection 4.3.3.

2.1.4 CONCLUSION

The methods described in Subsections 2.1.1 and 2.1.2 were used for the St. Lucie Units 1 and 2 IPA to identify the systems, structures, and components that are within the scope of license renewal and require an aging management review. The methods are consistent with and satisfy the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.1.5 REFERENCES

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2.1-3 Woody, C. O. (FPL) letter to Miraglia, F. J. (NRC), "St. Lucie Unit 2, 10 CFR 50.61(b)(1) Report," January 23, 1986.

2.1-4 Woody, C. O. (FPL) letter to Miraglia, F. J. (NRC), "St. Lucie Unit 2, 10 CFR 50.61(b)(1) Report," February 4, 1986.

2.1-5 Woody, C. O. (FPL) letter to Ashok, A. C. (NRC), "St. Lucie Unit 1, Protection Against Pressurized Thermal Shock Event," October 2, 1986.

2.1-6 Tourigny, E. G. (NRC) letter to Woody, C. O. (FPL), "Projected Values of Material Properties for Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," February 10, 1987.

2.1-7 Bohlke, W. H. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, 10 CFR 50.61 Evaluation of Pressurized Thermal Shock of Reactor Vessel Beltline Materials," May 14, 1996.

2.1-8 Stall, J. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, 10 CFR 50.61 Evaluation of Pressurized Thermal Shock of Reactor Vessel Beltline Materials - Supplement," September 23, 1996.

2.1-9 Stall, J. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Request for Additional Information (RAI) Response - 10 CFR 50.61 Pressurized Thermal Shock Evaluation," January 14, 1997.

2.1-10 Stall, J. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Request for Additional Information Response - 10 CFR 50.61 Pressurized Thermal Shock Evaluation," May 16, 1997.

2.1-11 Wiens, L. A. (NRC) letter to Plunkett, T. F. (FPL), "St. Lucie Units 1 and 2 - Pressurized Thermal Shock," October 27, 1997.

2.1-12 Woody, C. O. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Anticipated Transients Without Scram (ATWS) Plant Specific Information," July 15, 1987.

2.1-13 Conway, W. F. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Request for Additional Information - Anticipated Transients Without Scram," August 15, 1988.

2.1-14 Conway, W. F. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Request for Additional Information - Anticipated Transients Without Scram (ATWS)," February 28, 1989.

2.1-15 Conway, W. F. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Request for Additional Information - Anticipated Transients Without Scram," May 30, 1989.

2.1-16 Norris, J. A. (NRC) letter to FPL, "Summary of Meeting with Florida Power and Light Company to Discuss Implementation of 10 CFR 50.62 – ATWS Rule," June 8, 1989.

2.1-17 Norris, J. A. (NRC) letter to Woody, C. O. (FPL), "Compliance with the ATWS Rule, 10 CFR 50.62 – St. Lucie Plant Units 1 and 2," September 6, 1989.

2.1-18 Sager, D. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Anticipated Transients Without Scram," November 30, 1989.

2.1-19 Sager, D. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Anticipated Transients Without Scram," May 22, 1990.

2.1-20 D. A. Sager (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 2, Anticipated Transients Without Scram," November 26, 1990.

2.1-21 Conway, W. F. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Information to Resolve Station Blackout," April 17, 1989.

2.1-22 Sager, D. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Information to Resolve Station Blackout," March 7, 1990.

2.1-23 Norris, J. A. (NRC) letter to Goldberg, J. H. (FPL), "St. Lucie Units 1 and 2 – 10 CFR 50.63 – Station Blackout," September 12, 1991.

2.1-24 Sager, D. A. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Safety Evaluation on Station Blackout Rule," November 26, 1991.

2.1-25 Norris, J. A. (NRC) letter to Goldberg, J. H. (FPL), "St. Lucie Units 1 and 2 – 10 CFR 50.63 – Station Blackout," June 11, 1992.

2.1-26 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

2.1-27 NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," U. S. Nuclear Regulatory Commission, April 2001.

2.1-28 NUREG-0933, "A Prioritization of Generic Safety Issues," Supplement 24, U. S. Nuclear Regulatory Commission, June 2000.

2.1-29 Memorandum, Thadani, A. C. Director, Office of Nuclear Regulatory Research, to Travers, W. D., Executive Director of Operations - Closeout of Generic Safety Issue 190, "Fatigue Evaluation of Metal Components for 60 Year Plant Life," U. S. Nuclear Regulatory Commission, December 26, 1999.

TABLE 2.1-1
RADIOLOGICAL CONSEQUENCES OF ACCIDENTAL RELEASES

St. Lucie Unit 1 Design Basis Event	Whole Body	Thyroid
Part 100 Limits	25 Rem	300 Rem
Waste Gas Decay Tank Leakage or Rupture[1]	0.128 Rem	0.000878 Rem
Fuel Handling Accident[1] Dropped Fuel Assembly (Extended Burnup)	0.176 Rem	17.4 Rem
Cask Drop (Extended Burnup)	0.00561 Rem	1.5 Rem

NOTES: 1. 0-2 hour Exclusion Area Boundary Dose based on U. S. Atomic Energy Commission (AEC) Safety Guide 4 model (Unit 1 UFSAR Table 15.4.1-5).

St. Lucie Unit 2 Design Basis Event	Whole Body	Thyroid
Part 100 Limits	25 Rem	300 Rem
Radioactive Liquid Waste System Leak or Failure[1]	0.88 Rem	0.18 Rem
Waste Gas Decay Tank Failure[1]	0.013 Rem	0.0011 Rem
Spent Fuel Cask Drop[1]	0.0061 Rem	24 Rem
Fuel Handling Accident (dropped fuel assembly)[2]	<1.0 Rem	36 Rem

NOTES:
1. 0-2 hour Exclusion Area Boundary Dose (taken from Unit 2 UFSAR Section 15.7)
2. 0-2 hour Exclusion Area Boundary Dose (taken from NUREG-0843 Table 15.3)

2.2 PLANT LEVEL SCOPING RESULTS

St. Lucie Nuclear Plant's Integrated Plant Assessment (IPA) methodology consists of scoping, screening, and aging management reviews. This section provides the plant level scoping results achieved when applying the scoping methodology described in Subsection 2.1.1 to plant systems and structures. Tables 2.2-1, 2.2-2, and 2.2-3 provide the plant level scoping results for mechanical systems, structures, and electrical/I&C systems, respectively. If a system or structure, in whole or in part, meets one or more of the license renewal scoping criteria, the system or structure is considered to be within the scope of license renewal. Also included in the tables are references to the sections in this application that discuss screening results for in-scope systems and structures.

The mechanical plant systems identified as in-scope for St. Lucie Units 1 and 2 license renewal are consistent with the list of plant systems evaluated in the GALL Report [Reference 2.1-26], except as noted in Table 2.2-1. The scoping of structures and electrical/I&C components for St. Lucie is consistent with the GALL Report. Unless noted otherwise, the systems for St. Lucie Units 1 and 2 are the same.

Figure 2.2-1 provides a layout of St. Lucie Units 1 and 2 and identifies the structures within the scope of license renewal in bold. Figure 2.2-2 provides a layout of the structural components included in the structure identified as "Yard Structures."

TABLE 2.2-1
LICENSE RENEWAL SCOPING RESULTS FOR MECHANICAL SYSTEMS

System Name	System in License Renewal Scope?	Screening Results Application Subsection
Air Blower	No	
Auxiliary Feedwater and Condensate	Yes	2.3.4.3
Blowdown Cooling	No	
Blowdown Waste Management	No	
Cathodic Protection	No	
Chemical and Volume Control	Yes	2.3.3.1
Chemical Feed	No	
Circulating Water	No	
Component Cooling Water	Yes	2.3.3.2
Condensate Polishing	No	
Condensate Recovery	No	
Containment Airborne Radioactivity Removal (Unit 1 only)	No	
Containment Cooling	Yes	2.3.2.1
Containment Isolation	Yes	2.3.2.3
Containment Post Accident Monitoring	Yes	2.3.2.5
Containment Spray	Yes	2.3.2.2
Demineralized Makeup Water	Yes[1] (Unit 2 only)	2.3.3.3
Demineralized Water	No	
Diesel Generators and Support Systems	Yes	2.3.3.4
Emergency Cooling Canal	Yes	2.3.3.5
Extraction Steam	No[2]	
Fire Protection	Yes	2.3.3.6
Fuel Pool Cooling	Yes	2.3.3.7
Heater Drains and Vents	No	
Hypochlorite	No	
Instrument Air	Yes	2.3.3.8
Intake Cooling Water	Yes	2.3.3.9
Main Feedwater and Steam Generator Blowdown	Yes	2.3.4.2
Main Steam, Auxiliary Steam, and Turbine (includes Main Generator)	Yes	2.3.4.1

NOTES:
1. Although this system is not evaluated in the GALL Report, it was determined to perform a system intended function that satisfies the scoping criteria of 10 CFR 54.4(a).
2. Although this system is evaluated in the GALL Report, it was determined to not perform a system intended function that satisfies the scoping criteria of 10 CFR 54.4(a) and thus is not within the scope of license renewal.

TABLE 2.2-1 (continued)
LICENSE RENEWAL SCOPING RESULTS FOR MECHANICAL SYSTEMS

System Name	System in License Renewal Scope?	Screening Results Application Subsection
Meteorological Monitoring	No	
Miscellaneous Bulk Gas Supply	Yes[1]	2.3.3.10
Miscellaneous Drains	No	
Neutralization Basin	No	
Primary Makeup Water	Yes[1]	2.3.3.11
Processed Blowdown	No	
Reactor Coolant	Yes	2.3.1
Safety Injection	Yes	2.3.2.4
Sampling	Yes[1]	2.3.3.12
Security	No	
Service Water	Yes[1]	2.3.3.13
Sluice Water	No	
Steam Generator Blowdown Treatment Facility – Demineralization	No	
Steam Generator Blowdown Treatment Facility - Radiation Monitoring	No	
Steam Generator Blowdown Treatment Facility - Spent Resin	No	
Turbine Cooling Water	Yes[1] (Unit 1 only)	2.3.3.14
Turbine Lube Oil	No	
Ventilation	Yes	2.3.3.15
Waste Management	Yes[1]	2.3.3.16
Water Treatment Plant and Ecolochem Facility	No	
Wet Lay-up	No	

NOTES: 1. Although this system is not evaluated in the GALL Report, it was determined to perform a system intended function that satisfies the scoping criteria of 10 CFR 54.4(a).

TABLE 2.2-2
LICENSE RENEWAL SCOPING RESULTS FOR STRUCTURES

Structure Name	Structure in License Renewal Scope?	Screening Results Application Subsection
Backfit Maintenance Shop	No	
Cafeteria	No	
Carpenter Shop	No	
Chemical Storage Facility	No	
Coatings and Coatings Storage Facilities	No	
Component Cooling Water Areas	Yes	2.4.2.1
Condensate Polisher Building (Unit 1 only)	Yes	2.4.2.2
Condensate Storage Tank Enclosures	Yes	2.4.2.3
Containments	Yes	2.4.1
D-13 Building	No	
Diesel Oil Equipment Enclosures	Yes	2.4.2.4
Dry Storage Warehouse	No	
Emergency Diesel Generator Buildings	Yes	2.4.2.5
F4 Warehouse	No	
Fire House	No	
Fire Rated Assemblies	Yes	2.4.2.6
Fleet Services Building and Fuel Dispensing Facility	No	
Fuel Handling Buildings	Yes	2.4.2.7
Fuel Handling Equipment	Yes	2.4.2.8
G1 and G2 Warehouses	No	
Gas House	No	
Hot Tool Room	No	
Intake and Discharge Pipelines	No	
Intake, Discharge, and Emergency Cooling Canals	Yes	2.4.2.9
Intake Structures	Yes	2.4.2.10
Intake Velocity Caps	No	
Meteorological Tower	No	
North Security Building	No	
North Service Building (including maintenance shop)	No	
NPS Lunchroom	No	

TABLE 2.2-2 (continued)
LICENSE RENEWAL SCOPING RESULTS FOR STRUCTURES

Structure Name	Structure in License Renewal Scope?	Screening Results Application Subsection
Oil Storage Facility	No	
Other Miscellaneous Buildings	No	
Reactor Auxiliary Buildings	Yes	2.4.2.11
Rotating Maintenance Shop	No	
Sodium Hypochlorite Control Room	No	
South Security Building	No	
South Service Building	No	
St. Lucie and Hutchinson Island Substations	No	
Steam Generator Blowdown Treatment Facility	No	
Steam Trestle Areas	Yes	2.4.2.12
Switchyard	No	
Turbine Buildings	Yes	2.4.2.13
Ultimate Heat Sink Dam	Yes	2.4.2.14
Valve and Welding Building	No	
Welding Shop	No	
Yard Structures	Yes	2.4.2.15

TABLE 2.2-3
LICENSE RENEWAL SCOPING RESULTS FOR ELECTRICAL/I&C SYSTEMS

System Name	System in License Renewal Scope?	Screening Results Application Section
120/208V Electrical	Yes	2.5
120V Vital AC	Yes	2.5
125V DC	Yes	2.5
4.16kV Electrical	Yes	2.5
480V Electrical	Yes	2.5
6.9kV Electrical	Yes	2.5
Communications	Yes	2.5
Computer Process and Reactivity	No	
Containment Electrical Penetrations (conductor, non-metallic, and non-pressure boundary portions)	Yes	2.5
Data Acquisition Remote Terminal Unit	Yes	2.5
Generation and Distribution (includes Main, Auxiliary, and Start-up Transformers and the Switchyard)	No	
Loose Parts Monitoring	No	
Meteorological Monitoring	No	
Miscellaneous (includes EQ commodities)	Yes	2.5
Nuclear Instrumentation	Yes	2.5
Reactor Protection	Yes	2.5
Reactor Regulating	No	
Safeguards Panels	Yes	2.5
Seismic Monitoring	No	
Station Grounding	Yes	2.5

FIGURE 2.2-1
ST. LUCIE PLANT STRUCTURES

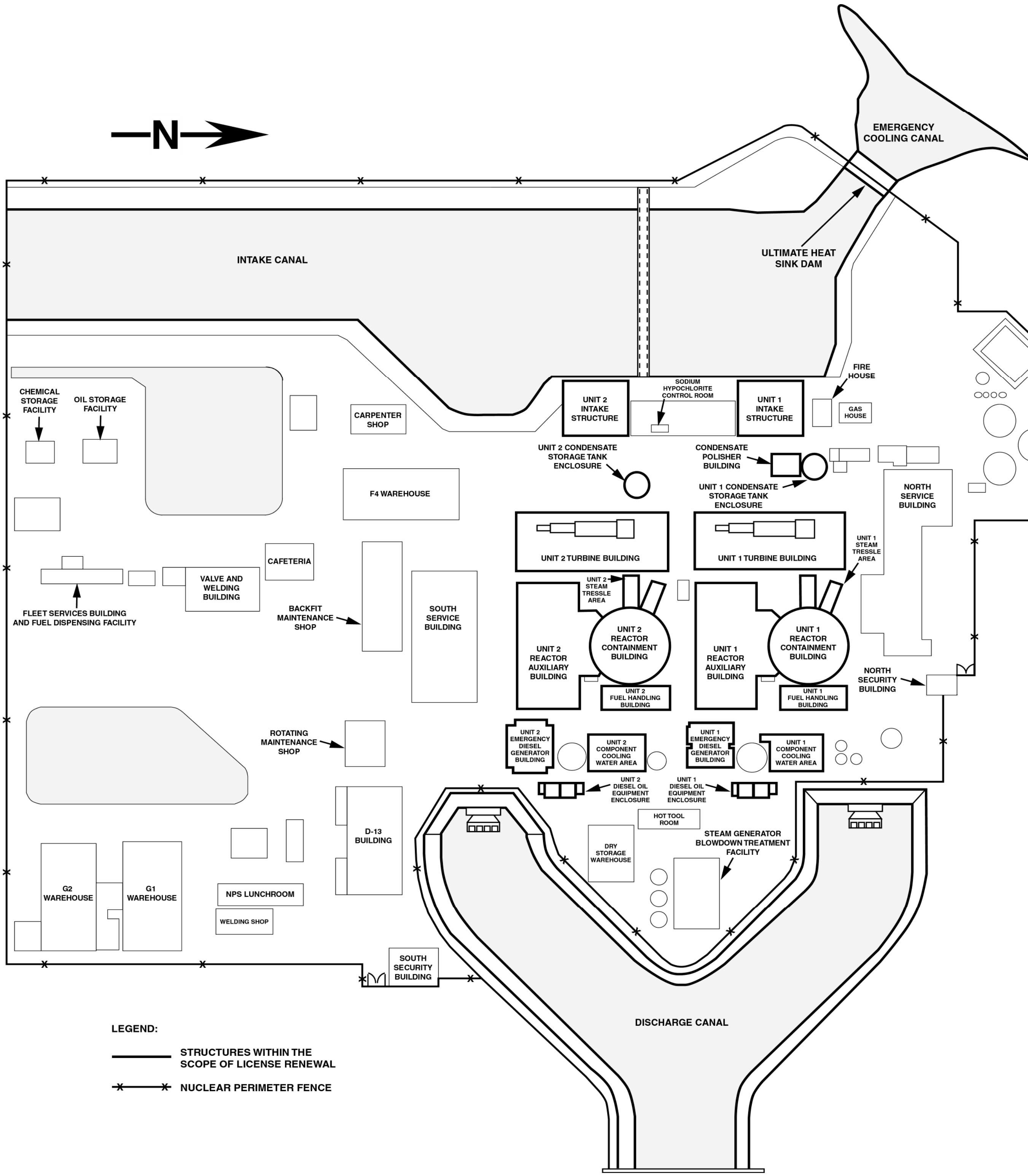
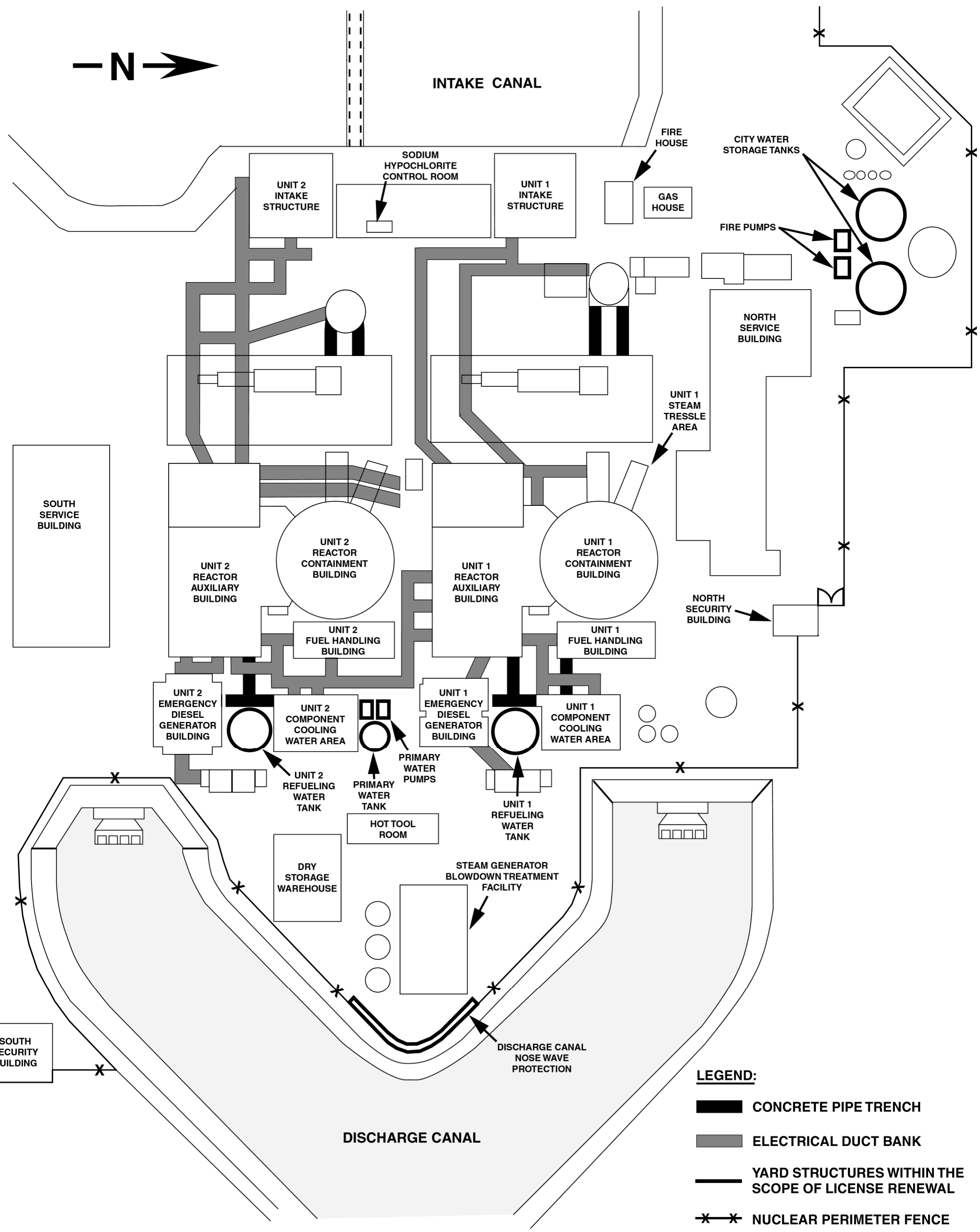


FIGURE 2.2-2
ST. LUCIE YARD STRUCTURES



2.3 SYSTEM SCOPING AND SCREENING RESULTS – MECHANICAL SYSTEMS

The determination of mechanical systems within the scope of license renewal is made by initially identifying St. Lucie Units 1 and 2 mechanical systems and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1 and the results of the mechanical systems review are contained in Section 2.2.

Section 2.1 also provides the methodology for determining the components within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The components that meet these screening requirements are identified in this section. These identified components subsequently require an aging management review for license renewal.

The screening results are provided below in four subsections:

- Reactor Coolant Systems
- Engineered Safety Features Systems
- Auxiliary Systems
- Steam and Power Conversion Systems

2.3.1 REACTOR COOLANT SYSTEMS

The Reactor Coolant Systems consist of the systems and components 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 Reactor Coolant Systems for St. Lucie Units 1 and 2 are the same, with no components common to both Units. The Reactor Coolant Systems are described in Unit 1 UFSAR Chapters 4 and 5 and Unit 2 UFSAR Chapters 4 and 5. The following components are included in this subsection:

- 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 show the evaluation boundaries for the portions of Reactor Coolant Systems that are within the scope of license renewal.

Reactor Coolant System components subject to aging management review include reactor vessels, control element drive mechanisms (pressure boundary only), pressurizers, steam generators, reactor vessel internals, reactor coolant pumps (pressure boundary only), piping, valves (pressure boundary only), and fittings.

Class 1, as used in this application, means the Safety Class 1 definition per 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 the ANSI B 31.7, 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 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, 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 reactor coolant pump 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

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 Unit 1 UFSAR Section 5.5.6 and Unit 2 UFSAR Section 5.4.3. Reactor coolant piping is presented in two parts:

- Class 1 piping
- Non-Class 1 piping

2.3.1.1.1 CLASS 1 PIPING

Class 1 Reactor Coolant System 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 Class 1 reactor coolant components requiring an aging management review include:

- Reactor coolant piping
- Pressurizer surge, spray, safety, and relief piping and valves
- 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
- Class 1 portions of ancillary systems attached to the Reactor Coolant Systems

Ancillary systems attached to the Reactor Coolant Systems include Safety Injection, Sampling, and Chemical and Volume Control.

2.3.1.1.2 NON-CLASS 1 PIPING

Several non-Class 1 Reactor Coolant System 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 non-Class 1 reactor coolant piping components requiring an aging management review include:

- 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 bleedoff piping and orifices

2.3.1.2 PRESSURIZERS

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 Unit 1 UFSAR Section 5.5.2 and Unit 2 UFSAR Section 5.4.10.

Piping attached to the pressurizers is Class 1 and is discussed in Subsection 2.3.1.1.1. Since piping with no intervening isolation valves interconnects sources of heat in the Reactor Coolant Systems, overpressure protection for the Reactor Coolant Systems is provided on the pressurizers. Overpressure protection consists of three spring-loaded ASME Code safety valves and two power-operated relief valves on each pressurizer.

2.3.1.3 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 vessels are described in Unit 1 UFSAR Section 5.4 and Unit 2 UFSAR Section 5.3.

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 aging management review 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. Incore flux measuring instruments and heated junction thermocouples enter the upper heads through the incore 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 the incore instrumentation flanges. Note 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 aging management review in accordance with 10 CFR 54.21(a)(1)(i).

2.3.1.4 REACTOR VESSEL INTERNALS

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

The components of the reactor vessel internals subject to license renewal aging management review can be divided into the following six groups for each Unit.

- 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 incore instrumentation plate assembly.
- 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 incore instrumentation guide tubes.

- 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. The Unit 2 reactor vessel internals design does not include a thermal shield.
- 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.
- 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.
- The incore instrumentation plate assembly supports the instrument guide tubes and incore thimbles. The incore instrumentation plate assembly is designed to provide a passageway and guidance for each instrument, as well as provide protection from reactor coolant cross-flow.

2.3.1.5 REACTOR COOLANT PUMPS

Each reactor coolant loop contains two vertically mounted, single bottom suction, horizontal discharge, centrifugal motor-driven pumps. The reactor coolant pumps 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 reactor coolant pumps is pressure boundary integrity. The reactor coolant pumps are described in Unit 1 UFSAR Section 5.5.5 and Unit 2 UFSAR Section 5.4.1.

The St. Lucie Units 1 and 2 reactor coolant pumps were manufactured by Byron Jackson. Associated components for the Class 1 reactor coolant pumps 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 reactor coolant pump seals are not subject to an aging management review 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 reactor coolant pump seal package and its constituent parts are routinely inspected and parts replaced, as required based on condition, for each reactor coolant pump
- Plant operating experience has demonstrated the effectiveness of these activities

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

2.3.1.6 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 steam generators are described in Unit 1 UFSAR Section 5.5.1 and Unit 2 UFSAR Section 5.4.2.

The Unit 1 steam generators were replaced in December of 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 reactor coolant pumps. 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.

2.3.1.7 SUMMARY

The Reactor Coolant 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 design basis events

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are a part of the Environmental Qualification Program
- SCs that are relied upon during certain postulated fire, SBO, PTS, and ATWS events

The Reactor Coolant System components subject to an aging management review and the component intended functions are provided in Table 3.1-1. The aging management review for the Reactor Coolant Systems is discussed in Section 3.1.

2.3.2 ENGINEERED SAFETY FEATURES SYSTEMS

Engineered Safety Features Systems consist of systems and components 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, the Engineered Safety Features Systems provide emergency coolant to assure 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 Engineered Safety Features Systems for St. Lucie Units 1 and 2 are the same.

The following systems are included in this subsection:

- Containment Cooling
- Containment Spray
- Containment Isolation
- Safety Injection (includes Shutdown Cooling)
- Containment Post Accident Monitoring

2.3.2.1 CONTAINMENT COOLING

Containment Cooling is designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a design basis event. In addition, the containment fan cooling units continue to operate after a design basis event to remove heat and to reduce the pressure in containment to atmospheric. Heat removed from the containment is transferred to Component Cooling Water. Component Cooling Water is screened in Subsection 2.3.3.2. Containment Cooling consists of four fan cooling units that are located outside the secondary shield wall inside each containment. Containment Cooling is described in Unit 1 UFSAR Section 6.2.2.2.2 and Unit 2 UFSAR Section 6.2.2.2.2.

The flow diagrams listed in Table 2.3-2 show the evaluation boundaries for the portions of Containment Cooling that are within the scope of license renewal.

Containment 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 design basis events
- SCs that are a part of the Environmental Qualification Program
- SCs that are relied upon during certain postulated fire events

Containment Cooling components subject to an aging management review include fan cooler housings and valves (pressure boundary only), heat exchangers, ducts, thermowells, flexible connections, drip pans, piping, and fittings. The intended functions of Containment Cooling components subject to an aging management review include pressure boundary integrity and heat transfer. A complete list of Containment Cooling components requiring an aging management review and the component intended functions are provided in Table 3.2-1. The aging management review for the Containment Cooling is discussed in Section 3.2.

2.3.2.2 CONTAINMENT SPRAY

Containment Spray is designed to remove sufficient heat to maintain the containments below their design pressure and temperature limits following design basis events. Containment Spray is described in Unit 1 USFAR Section 6.2.2.2.1 and Unit 2 UFSAR Section 6.2.2.2.1.

Containment spray 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 screened with Safety Injection in Subsection 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 screened with civil/structural components in Subsection 2.4.1.1.

The flow diagrams listed in Table 2.3-2 show the evaluation boundaries for the portions of Containment Spray that are within the scope of license renewal.

Containment Spray 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are a part of the Environmental Qualification Program
- SCs that are relied upon during certain postulated fire (Units 1 and 2) and SBO events (Unit 2 only)

Containment Spray components subject to an aging management review 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, sightglasses, piping, tubing, and fittings. The intended functions for Containment Spray components subject to an aging management review include pressure boundary integrity, heat transfer, vortex prevention, spray, throttling, and filtration. A complete list of Containment Spray components requiring an aging management review and the component intended functions are provided in Table 3.2-2. The aging management review for Containment Spray is discussed in Section 3.2.

2.3.2.3 CONTAINMENT ISOLATION

Containment Isolation is an engineered safety feature that provides for the closure or integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment. Containment Isolation is described in Unit 1 UFSAR Section 6.2.4 and Unit 2 UFSAR Section 6.2.4.

Process systems that have license renewal system intended functions in addition to the containment isolation function are included in the system screening results described elsewhere in Section 2.3.

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 described in Section 2.4.

The non-metallic and conductor portions of containment electrical penetrations are included in the electrical/I&C screening described in Section 2.5.

Note that all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described, require an aging management review.

Containment Purge, Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), Integrated Leak Rate Test, and Service Air are process systems whose only license renewal system intended function is containment isolation. Containment Vacuum Relief is included in this screening section even though it performs a function in addition to the containment isolation function. The additional function is to protect the containment vessels from subatmospheric internal pressure conditions created by a containment overcooling event. The flow diagrams listed in Table 2.3-2 show the evaluation boundaries for the portions of Containment Purge, Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), Integrated Leak Rate Test, Service Air, and Containment Vacuum Relief that are within the scope of license renewal.

Containment Purge 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 design basis events
- SCs that are a part of the Environmental Qualification Program

Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), and Service Air 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are a part of the Environmental Qualification Program (Unit 2 only)

Integrated Leak Rate Test 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions

Containment Vacuum Relief 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 design basis events
- SCs that are a part of the Environmental Qualification Program

Containment Purge, Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), Integrated Leak Rate Test, Service Air, and Containment Vacuum Relief components within the scope of license renewal and subject to aging management review include valves (pressure boundary only), piping, tubing, fittings, and debris screens. The intended functions for Containment Purge, Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), Integrated Leak Rate Test, Service Air, and Containment Vacuum Relief components subject to an aging management review include pressure boundary integrity and filtration. Containment Purge, Hydrogen Purge (Unit 1 only), Continuous Containment/Hydrogen Purge (Unit 2 only), Integrated Leak Rate Test, Service Air, and Containment Vacuum Relief components requiring an aging management review and the component intended functions are listed in Table 3.2-3. The aging management review for Containment Isolation is discussed in Section 3.2.

2.3.2.4 SAFETY INJECTION

Safety Injection, which includes the safety injection tanks, provides emergency core cooling and reactivity control during and following design basis events. Portions of Safety Injection are also used for shutdown cooling functions. In addition, some portions of Safety Injection, including the shutdown cooling heat exchangers, are used in conjunction with Containment Spray to cool the Containment. Safety Injection is described in Unit 1 UFSAR Section 6.3 and Unit 2 UFSAR Section 6.3. Shutdown cooling and the safety injection components required to perform shutdown cooling functions are described in Unit 1 UFSAR Section 9.3.5 and Unit 2 UFSAR Section 5.4.7.

The flow diagrams listed in Table 2.3-2 show the evaluation boundaries for the portions of Safety Injection that are within the scope of license renewal.

Safety Injection 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are a part of the Environmental Qualification Program
- SCs that are relied upon during certain postulated fire (Units 1 and 2) and SBO events (Unit 2 only)

Safety Injection components subject to an aging management review include safety injection tanks, pumps and valves (pressure boundary only), heat exchangers, orifices, thermowells, piping, tubing, and fittings. The intended functions for Safety Injection components subject to an aging management review include pressure boundary integrity, heat transfer, and throttling. A complete list of Safety Injection components requiring an aging management review and the component intended functions are provided in Table 3.2-4. The aging management review for Safety Injection is discussed in Section 3.2.

2.3.2.5 CONTAINMENT POST ACCIDENT MONITORING

Containment Post Accident Monitoring includes the following subsystems:

- Containment Hydrogen Monitoring
- Post Accident Sampling (Unit 2 only)
- Containment Atmosphere Radiation Monitoring

This subsection addresses the mechanical SCs that are required to support the system intended functions of these subsystems. The screening results for electrical/I&C SCs are provided in Section 2.5 of this application.

The flow diagrams listed in Table 2.3-2 show the evaluation boundaries for the portions of Containment Post Accident Monitoring that are within the scope of license renewal.

Containment hydrogen monitoring provides indication of the hydrogen gas concentration in the containment atmosphere following a loss-of-coolant accident. The mechanical portions of containment hydrogen monitoring provide a flow path from the containment to the hydrogen analyzers and then back to the containment. Containment hydrogen monitoring is described in Unit 1 UFSAR Section 6.2.5.2.3 and Unit 2 UFSAR Section 6.2.5.2.1.

The only mechanical portion of post accident sampling (Unit 2 only) in the scope of license renewal are valves that provide a pressure boundary for containment hydrogen monitoring. Post accident sampling is described in Unit 2 UFSAR Section 9.3.6.

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 atmosphere radiation monitoring is described in Unit 1 UFSAR Section 12.2.4.1 and Unit 2 UFSAR Section 12.3.4.2.3.1.

Containment Post Accident Monitoring 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are a part of the Environmental Qualification Program
- SCs that are relied upon during certain postulated fire (Unit 2 only) and SBO events (Unit 2 only)

Containment Post Accident Monitoring components subject to an aging management review include; valves (pressure boundary only), sample vessel, flexible hoses, piping, tubing, and fittings. The intended function for the Containment Post Accident Monitoring components subject to an aging management review is pressure boundary integrity. A complete list of Containment Post Accident Monitoring components requiring an aging management review and the component intended functions are provided in Table 3.2-5. The aging management review for Containment Post Accident Monitoring is discussed in Section 3.2.

2.3.3 AUXILIARY SYSTEMS

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. The following systems are included in this subsection:

- Chemical and Volume Control
- 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 Supply
- Primary Makeup Water
- Sampling
- Service Water
- Turbine Cooling Water (Unit 1 only)
- Ventilation
- Waste Management

2.3.3.1 CHEMICAL AND VOLUME CONTROL

Chemical and Volume Control provides a continuous feed and bleed for the Reactor Coolant System to maintain proper water level and to adjust boron concentration. Chemical and Volume Control consists of a charging subsystem, a letdown subsystem, and a boric acid makeup subsystem. Chemical and Volume Control is described in Unit 1 UFSAR Section 9.3.4 and Unit 2 UFSAR Section 9.3.4.

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

Chemical and Volume Control 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 design basis events

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires and SBO events

Chemical and Volume Control components subject to an aging management review include pumps and valves (pressure boundary only), housings, tanks, heat exchangers, strainers, orifices, thermowells, piping, tubing, and fittings. The intended functions for Chemical and Volume Control components subject to an aging management review include pressure boundary integrity, filtration, and throttling. For a complete list of Chemical and Volume Control components that require aging management review and the component intended functions, see Table 3.3-1. The aging management review for Chemical and Volume Control is discussed in Section 3.3.

2.3.3.2 COMPONENT COOLING WATER

Component Cooling Water 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 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. Component Cooling Water is described in Unit 1 UFSAR Section 9.2.2 and Unit 2 UFSAR Section 9.2.2.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Component Cooling Water that are within the scope of license renewal. Note: Other coolers and heat exchangers cooled by Component Cooling Water were considered part of their respective systems. Accordingly, these other coolers and heat exchangers were screened with those systems.

Component Cooling Water 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires

Component Cooling Water components subject to an aging management review include pumps and valves (pressure boundary only), heat exchangers, tanks, orifices, thermowells, sightglasses, piping, tubing, and fittings. The intended functions for Component Cooling Water components subject to an aging management review include pressure boundary integrity, heat transfer, and throttling. For a complete list of Component Cooling Water components that require aging management review and the component intended functions, see Table 3.3-2. The aging management review for Component Cooling Water is discussed in Section 3.3.

2.3.3.3 DEMINERALIZED MAKEUP WATER (Unit 2 only)

Demineralized Makeup Water provides makeup to various systems throughout the plant. Demineralized Makeup Water is described in Unit 2 UFSAR Section 9.2.3.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Demineralized Makeup Water that are within the scope of license renewal.

Demineralized Makeup Water is in the scope of license renewal because it contains:

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions

Demineralized Makeup Water components subject to an aging management review include valves (pressure boundary only), piping, and fittings. The intended function for Demineralized Makeup Water components subject to an aging management review is pressure boundary integrity. For a complete list of Demineralized Makeup Water components that require aging management review and the component intended functions, see Table 3.3-3. The aging management review for Demineralized Makeup Water is discussed in Section 3.3.

2.3.3.4 DIESEL GENERATORS AND SUPPORT SYSTEMS

The Diesel Generators provide AC power to the onsite electrical distribution system to assure the capability for a safe and orderly shutdown. The Diesel Generator Support Systems necessary to ensure proper operation of the Diesel Generators are:

- Air Intake and Exhaust
- Air Start
- Fuel Oil
- Lube Oil
- Cooling Water

The Diesel Generators are described in Unit 1 UFSAR Section 8.3 and Unit 2 UFSAR Section 8.3. The Diesel Generator Support Systems are described in Unit 1 UFSAR Section 9.5 and Unit 2 UFSAR Section 9.5.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Diesel Generators and Support Systems that are within the scope of license renewal.

Diesel Generators 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires (Units 1 and 2) and SBO events (Note: The Unit 2 Diesel Generators and Support Systems are required during Unit 1 SBO events. No Diesel Generators are required for Unit 2 SBO events.)

Diesel Generators and Support Systems components subject to an aging management review include pumps, valves, air start motors (pressure boundary only), tanks, heat exchangers, silencers, flame arrestors, filters, strainers, flexible hoses, expansion joints, orifices, thermowells, sightglasses, piping, tubing, and fittings. The intended functions for Diesel Generators and Support Systems components subject to an aging management review include pressure boundary integrity, filtration, heat transfer, throttling, and fire spread prevention. For a complete list of Diesel Generators and Support Systems components that require aging management review and component intended functions, see Table 3.3-4. The aging management review for Diesel Generators and Support Systems is discussed in Section 3.3.

2.3.3.5 EMERGENCY COOLING CANAL

The Emergency Cooling Canal mechanical components, located at the Ultimate Heat Sink Dam, admit 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. The Emergency Cooling Canal is described in Unit 1 UFSAR Section 9.2.7 and Unit 2 UFSAR Section 9.2.5.

The flow diagram listed in Table 2.3-3 shows the evaluation boundaries for the portions of the Emergency Cooling Canal that are within the scope of license renewal.

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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions

Emergency Cooling Canal components subject to an aging management review include valves (pressure boundary only), piping, and fittings. The intended function for Emergency Cooling Canal components subject to an aging management review is pressure boundary integrity. For a complete list of Emergency Cooling Canal components that require aging management review and the component intended functions, see Table 3.3-5. The aging management review for Emergency Cooling Canal components is discussed in Section 3.3.

2.3.3.6 FIRE PROTECTION

Fire Protection protects plant equipment to ensure safe plant shutdown in the event of a fire. Fire Protection consists of fire suppression water distribution and spray, reactor coolant pump oil collection, and reactor auxiliary building cable spreading room Halon (Unit 1 only). Fire rated assemblies, fire barriers, and structural components required to ensure adequate Halon concentrations (if actuated) are included in the civil/structural screening described in Section 2.4. Fire detection is included in the electrical/I&C screening described in Section 2.5. Fire Protection is described in Unit 1 UFSAR Section 9.5A, Section 3.1.3, and Unit 2 UFSAR Section 9.5A, Section 3.1.3.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Fire Protection that are within the scope of license renewal.

Fire Protection is in the scope of license renewal because it contains:

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires

Fire extinguishers, fire hoses, and air packs are not subject to an aging management review in accordance with 10 CFR 54.21(a)(1)(ii) because they are replaced based on condition in accordance with National Fire Protection Association (NFPA) standards and plant surveillance procedures for fire protection equipment. This position is consistent with the guidance of NEI 95-10 [Reference 2.3-1]. The following standards are utilized as the basis and guidance for inspection and replacement in accordance with various internal FPL procedures:

- NFPA 10, "Portable Fire Extinguishers"
- NFPA-14, "Standpipe and Hose Systems"
- NUREG/CR-0041, "Manual of Respiratory Protection Against Airborne Radioactive Material"

Additionally, the Nuclear Electric Insurance Limited (NEIL), Property Loss Prevention Standard, Appendix R of 10 CFR 50, and various NUREG reports and NRC Regulatory Guides are utilized for guidance.

Fire Protection components subject to an aging management review include pumps and valves (pressure boundary only), tanks, flame arrestors, sprinkler heads, nozzles, sightglasses, enclosures (reactor coolant pump oil collection), filters, vortex breakers, hydrants, flexible hoses, drip pans, orifices, piping, tubing, and fittings. Hose stations are included as component types "nozzles" and "fittings" in Section 3.3 and shown in Table 3.3-6. Hose racks are included as component type "component supports (non-safety related)" in the civil/structural aging management review in Subsection 3.5.2. The intended functions for Fire Protection components subject to an aging management review include pressure boundary integrity, throttling, fire spread prevention, filtration, vortex prevention, and spray. For a complete list of the Fire Protection components that require aging management review and the component intended functions, see Tables 3.3-6 and 3.5-8. The aging management reviews for Fire Protection are discussed in Section 3.3 and Subsection 3.5.2.

2.3.3.7 FUEL POOL COOLING

During normal operation, Fuel Pool Cooling removes decay heat from the fuel pool by circulating water through the fuel pool heat exchangers. The heat from the fuel pool is transferred to Component Cooling Water.

The safety related means of Fuel Pool Cooling for Unit 1 is pool boil off and system makeup from Intake Cooling Water (see Subsection 2.3.3.9) 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 boil off and system makeup from Intake Cooling Water (See Subsection 2.3.3.9).

Fuel Pool Cooling is described in Unit 1 UFSAR Section 9.1.3 and Unit 2 UFSAR Section 9.1.3.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Fuel Pool Cooling that are within the scope of license renewal.

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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions

Fuel Pool Cooling components subject to an aging management review 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 aging management review include pressure boundary integrity and heat transfer (Unit 2 only). For a complete list of Fuel Pool Cooling components that require aging management review and the component intended functions, see Table 3.3-7. The aging management review for Fuel Pool Cooling is discussed in Section 3.3.

2.3.3.8 INSTRUMENT AIR

Instrument Air provides a reliable source of dry, oil-free air for instrumentation and controls, and pneumatic valves. Instrument Air provides motive power and control air to safety-related and non-safety related components. Instrument Air is described in Unit 1 UFSAR Section 9.3.1 and Unit 2 UFSAR Section 9.3.1.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Instrument Air that are within the scope of license renewal. Note that some of the license renewal boundaries have been established at normally open valves. This approach is considered acceptable for Instrument Air for the following reasons:

- 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 only required 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:

- SCs that are safety related and are relied upon to remain functional during and following design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions

- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires (Units 1 and 2) and SBO events (Unit 1 only)

Instrument Air components subject to an aging management review include valves (pressure boundary only), receivers, accumulators, dryers, filters, strainers, heat exchangers, flexible hoses, orifices, silencers, thermowells, sightglasses, rupture discs, piping, tubing, and fittings. The intended functions for Instrument Air components subject to an aging management review include pressure boundary integrity, heat transfer, filtration, and throttling. For a complete list of Instrument Air components that require aging management review and the component intended functions, see Table 3.3-8. The aging management review for Instrument Air is discussed in Section 3.3.

2.3.3.9 INTAKE COOLING WATER

Intake Cooling Water removes heat from Component Cooling Water and Turbine Plant Cooling Water. The Intake Cooling Water pumps supply salt water from the intake area for each Unit through two redundant piping headers per Unit to the tube side of the Component Cooling Water and Turbine Plant Cooling Water heat exchangers. Flow is routed from the heat exchangers to the Discharge Canal. Additionally, Intake Cooling Water provides a safety-related makeup source for Fuel Pool Cooling (see Subsection 2.3.3.7). Intake Cooling Water is described in Unit 1 UFSAR Section 9.2.1 and Unit 2 UFSAR Section 9.2.1.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Intake Cooling Water that are within the scope of license renewal. Note: The Component Cooling Water heat exchangers were considered to be part of Component Cooling Water and were screened with that system (see Subsection 2.3.3.2).

Intake Cooling Water 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires

Intake Cooling Water components subject to an aging management review include pumps and valves (pressure boundary only), strainers, expansion joints, thermowells, orifices, piping, tubing, and fittings. The intended functions for Intake Cooling Water components subject to an aging management review include pressure boundary integrity, filtration, and throttling. For a complete list of Intake Cooling Water components that require aging management review and the component intended functions, see Table 3.3-9. The aging management review for Intake Cooling Water is discussed in Section 3.3.

2.3.3.10 MISCELLANEOUS BULK GAS SUPPLY

Miscellaneous Bulk Gas Supply consists of various storage facilities and associated components for supplying hydrogen, carbon dioxide, and nitrogen required for plant operation. The common Miscellaneous Bulk Gas Supply storage facility is described in Unit 1 UFSAR Section 9.3.1.

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 flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Miscellaneous Bulk Gas Supply that are within the scope of license renewal.

Miscellaneous Bulk Gas Supply 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires

Miscellaneous Bulk Gas Supply components subject to an aging management review include valves (pressure boundary only), vessels, piping, tubing, and fittings. The intended function for Miscellaneous Bulk Gas Supply components subject to an aging management review is pressure boundary integrity. For a complete list of Miscellaneous Bulk Gas Supply components that require aging management review and the component intended functions, see Table 3.3-10. The aging management review for Miscellaneous Bulk Gas Supply is discussed in Section 3.3.

2.3.3.11 PRIMARY MAKEUP WATER

Primary Makeup Water provides treated, demineralized water for makeup to various systems throughout the plant. Primary Makeup Water is described in Unit 1 UFSAR Section 9.2.5 and Unit 2 UFSAR Section 9.2.3.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Primary Makeup Water that are within the scope of license renewal. Note that some of these license renewal boundaries for Unit 2 Primary Makeup Water have been established at normally open valves. This approach is considered acceptable because Unit 2 Primary Makeup Water is only required in the unlikely event of a fire in the Unit 2 Containment or Unit 2 Fuel Handling Building, and these open boundary valves are closed, as necessary, for these fire scenarios.

Primary Makeup Water 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program (Unit 2 only)
- SCs that are relied on during postulated fires (Unit 2 only)

Primary Makeup Water components subject to an aging management review include tanks, pumps, and valves (pressure boundary only), nozzles, vortex breakers, expansion joints, orifices, piping, tubing, and fittings. Unit 2 Primary Makeup Water provides the fire suppression water to the Unit 2 Containment and Unit 2 Fuel Handling Building. Hose stations in the Unit 2 Containment and Unit 2 Fuel Handling Building are included as component types "nozzles" and "fittings" in Section 3.3 and shown in Table 3.3-11. Hose racks are included as component type "component supports (non-safety related)" in the civil/structural aging management review in Section 3.5 and shown on Tables 3.5-2 and 3.5-9. The intended functions for Primary Makeup Water components subject to an aging management review include pressure boundary integrity, vortex prevention, spray, and throttling. For a complete list of Primary Makeup Water components that require aging management review and the component intended functions, see Table 3.3-11. The aging management review for Primary Makeup Water is discussed in Section 3.3.

2.3.3.12 SAMPLING

Sampling provides the means to obtain samples from the Reactor Coolant System and Auxiliary Systems during all modes of operation for chemical and radiological analysis. Sampling is described in Unit 1 UFSAR Section 9.3.2 and Unit 2 UFSAR Section 9.3.2.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Sampling that are within the scope of license renewal.

Sampling 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program (Unit 2 only)
- SCs that are relied on during postulated fires (Units 1 and 2) and SBO events (Unit 1 only)

Sampling components subject to an aging management review include valves (pressure boundary only), tubing, and fittings. The intended function for Sampling components subject to an aging management review is pressure boundary integrity. For a complete list of Sampling components that require aging management review and the component intended functions, see Table 3.3-12. The aging management review for Sampling is discussed in Section 3.3.

2.3.3.13 SERVICE WATER

Service Water supports Fire Protection and supplies water to the plant washdown stations, decontamination facilities, and potable water system. This System is a common site service water supply for Units 1 and 2. Service Water is described in Unit 1 UFSAR Section 9.2.6 and Unit 2 UFSAR Section 9.2.4.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Service Water that are within the scope of license renewal.

Service Water is in the scope of license renewal because it contains:

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires

Service Water components subject to an aging management review include pumps and valves (pressure boundary only), piping, and fittings. The intended function for Service Water components subject to an aging management review is pressure boundary integrity. For a complete list of the Service Water components that require aging management review and the component intended functions, see Table 3.3-13. The aging management review for Service Water is discussed in Section 3.3.

2.3.3.14 TURBINE COOLING WATER (Unit 1 only)

Turbine Cooling Water is a closed-loop system used to remove heat from the turbine and other components in the power cycle, including the Instrument Air compressors. Turbine Cooling Water is described in Unit 1 UFSAR Section 9.2.4.

The flow diagram listed in Table 2.3-3 shows the evaluation boundaries for the portions of Turbine Cooling Water that are within the scope of license renewal. Note that some of the license renewal boundaries have been established at normally open valves. This approach is considered acceptable for Turbine Cooling Water because the small portion of Unit 1 Turbine Cooling Water 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 open license renewal boundaries. Turbine Cooling Water is in the scope of license renewal because it contains:

- SCs that are relied on during SBO events (Unit 1 only)

Turbine Cooling Water components subject to an aging management review include pump and valves (pressure boundary only), tank, cooler, sightglasses, thermowells, piping, and fittings. The intended functions for Turbine Cooling Water components subject to an aging management review include pressure boundary integrity and heat transfer. For a complete list of the Turbine Cooling Water components that require aging management review and the component intended functions, see Table 3.3-14. The aging management reviews for Turbine Cooling Water are discussed in Section 3.3.

2.3.3.15 VENTILATION

Ventilation provides for heating, ventilation, and air conditioning to various buildings and rooms/areas throughout the plant. Ventilation includes the following subsystems: Control Room Air Conditioning, Emergency Core Cooling Systems 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.

Control Room Air Conditioning is designed to maintain habitability, temperature, and humidity inside each control room. During normal operation, Control Room Air Conditioning for each Unit draws air from its associated control room, passes air through air handling 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. Under emergency conditions, on receipt of a containment isolation signal, on receipt of a high radiation alarm on the intake radiation monitors, or on loss of power to the intake radiation monitors, 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 filters and charcoal adsorbers.

Emergency Core Cooling Systems Area Ventilation is designed as the necessary ventilation for the Emergency Core Cooling Systems area under accident conditions. This subsystem provides post-loss-of-coolant accident (LOCA) high-efficiency particulate filtration and iodine adsorption for air exhausted from the Emergency Core Cooling Systems areas.

Fuel Handling Building Ventilation (Unit 2 only) is designed to prevent buildup of airborne radioactivity in the building and ventilates the fuel pool cooling equipment contained in the building. During emergency operation, the subsystem is designed to automatically isolate and utilize Shield Building Ventilation to remove and filter air from the fuel pool area.

Intake Structure Ventilation (Unit 2 only) is designed to ventilate the intake cooling water pump enclosure. Two 100% capacity, independently powered exhaust fans ventilate the enclosure.

Miscellaneous Ventilation (Unit 1 only) provides ventilation for the Unit 1 computer room and the Unit 1 hot shutdown panel room.

Reactor Auxiliary Building Electrical and Battery Room Ventilation is designed as the primary intake and exhaust for air in the electrical equipment and battery rooms. The electrical equipment rooms are ventilated by a once-through filtered ventilation system that contains separate supply and exhaust fans.

Reactor Auxiliary Building Main Supply and Exhaust is designed as the primary intake and exhaust for air in each of the Reactor Auxiliary Buildings. The subsystems are designed to limit the temperature to an ambient temperature of 104^{o}F in the equipment areas with an outside temperature of 93^{o}F. The Reactor Auxiliary Buildings are ventilated by once-through filtered ventilation that contains separate supply and exhaust fans. The exhaust system serves no safety function.

Shield Building Ventilation maintains a slight negative pressure in each of the shield building annuli following a LOCA. Shield Building Ventilation mixes building in-leakage with the air in the annuli and any leakage from each of the Containments, and discharges it through filter trains that include charcoal adsorbers. The plant vent stacks are considered part of their respective Shield Building Ventilation Systems. However, 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.

Ventilation is described in Unit 1 UFSAR Sections 6.2 and 9.4 and Unit 2 UFSAR Sections 6.2 and 9.4.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Ventilation that are within the scope of license renewal.

Ventilation 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 design basis events
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires (Units 1 and 2) and SBO events (Unit 1 only)

Ventilation components subject to an aging management review include valves (pressure boundary only), filter housings, heat exchangers, flexible connections, ducts, demisters, thermowells, orifices, structural supports, piping, tubing, and fittings. The intended functions for Ventilation components subject to an aging management review include pressure boundary integrity, moisture removal, structural support, throttling, and heat transfer. Louvers and exhaust hoods in the scope of license renewal are screened in Subsection 2.4 with civil/structural components. Sealant materials are used to maintain the main control room at positive pressure with respect to adjacent areas. These sealant materials are included within the scope of license renewal as structural components and subject to an aging management review. These sealant materials are described in Subsection 3.5.2.4 and listed in Tables 3.5-8 and 3.5-12. For a complete list of Ventilation components that require aging management review and the component intended functions, see Table 3.3-15. The aging management review for Ventilation is discussed in Section 3.3.

2.3.3.16 WASTE MANAGEMENT

Waste Management 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. Waste Management also includes the safeguards pump room drains and equipment and floor drainage. Waste Management is 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.

The flow diagrams listed in Table 2.3-3 show the evaluation boundaries for the portions of Waste Management that are within the scope of license renewal.

Waste Management 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 design basis events

- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires

Waste Management components subject to an aging management review include valves (pressure boundary only), strainers, orifices, piping, and fittings. The intended functions for Waste Management components subject to an aging management review include pressure boundary integrity, filtration, and throttling. For a complete list of Waste Management components that require aging management review and the component intended functions, see Table 3.3-16. The aging management review for Waste Management is discussed in Section 3.3.

2.3.4 STEAM AND POWER CONVERSION SYSTEMS

The Steam and Power Conversion Systems act as a heat sink to remove heat from the reactor and convert the heat generated in the reactor to the plant's electrical output. Unless noted otherwise, the Steam and Power Conversion Systems for St. Lucie Units 1 and 2 are the same. The following systems are included in this subsection:

- Main Steam, Auxiliary Steam, and Turbine
- Main Feedwater and Steam Generator Blowdown
- Auxiliary Feedwater and Condensate

2.3.4.1 MAIN STEAM, AUXILIARY STEAM, AND TURBINE

Main Steam transports steam from the steam generators to the main turbines and other secondary steam system components. Main Steam provides the principal heat sink for the Reactor Coolant Systems, protects the Reactor Coolant Systems and the steam generators from overpressurization, provides isolation of the steam generators during postulated steam line breaks, and provides steam supply to the auxiliary feedwater pump turbines. Main Steam is described in Unit 1 UFSAR Section 10.3 and Unit 2 UFSAR Section 10.3. Steam generators are screened with the Reactor Coolant Systems in Subsection 2.3.1.6.

Auxiliary Steam provides 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 postulated fires and SBO events. The Turbine is described in Unit 1 UFSAR Section 10.2 and Unit 2 UFSAR Section 10.2.

The flow diagrams listed in Table 2.3-4 show the evaluation boundaries for the mechanical portions of Main Steam, Auxiliary Steam, and Turbine that are within the scope of license renewal. Note that some of the license renewal boundaries for Main Steam have been established at normally open valves. This approach is considered acceptable for Main Steam because the open Main Steam boundary valves are only required to mitigate potential spurious valve operation in the unlikely event of certain fires, and these open boundary valves are procedurally closed for these 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.

Main Steam, Auxiliary Steam, and Turbine 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires, SBO, and ATWS events

Main Steam, Auxiliary Steam, and Turbine components subject to an aging management review 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 aging management review are pressure boundary integrity, filtration, and throttling. For a complete list of Main Steam, Auxiliary Steam, and Turbine components that require aging management review and the component intended functions, see Table 3.4-1. The aging management review for Main Steam, Auxiliary Steam, and Turbine is discussed in Section 3.4.

2.3.4.2 MAIN FEEDWATER AND STEAM GENERATOR BLOWDOWN

Main Feedwater and Steam Generator Blowdown provide sufficient water flow to the steam generators to maintain an adequate heat sink for the Reactor Coolant System, provide for Main Feedwater and Steam Generator Blowdown isolation following a postulated LOCA or steam line break event, and assist in maintaining steam generator water chemistry.

Main Feedwater supplies pre-heated, 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. Main Feedwater is described in Unit 1 UFSAR Section 10.4.6 and Unit 2 UFSAR Section 10.4.7.

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. Steam Generator Blowdown is described in Unit 1 UFSAR Section 10.4.7 and Unit 2 UFSAR Section 10.4.8.

The flow diagrams listed in Table 2.3-4 show the evaluation boundaries for the portions of Main Feedwater and Steam Generator Blowdown that are within the scope of license renewal. Note that some of the license renewal boundaries for Steam Generator Blowdown have been established at normally open valves. This approach is considered acceptable for Steam Generator Blowdown because the open Steam Generator Blowdown boundary valves are only required to mitigate potential spurious valve operation in the unlikely event of certain fires, and these open boundary valves are procedurally closed for these fire scenarios.

Main Feedwater and Steam Generator Blowdown 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires and SBO events

Main Feedwater and Steam Generator Blowdown components subject to an aging management review include valves (pressure boundary only), accumulators, orifices, thermowells, piping, tubing, and fittings. The intended functions for the Main Feedwater and Steam Generator Blowdown components subject to an aging management review are pressure boundary integrity and throttling. For a complete list of Main Feedwater and Steam Generator Blowdown components that require aging management review and the component intended functions, see Table 3.4-2. The aging management review for Main Feedwater and Steam Generator Blowdown is discussed in Section 3.4.

2.3.4.3 AUXILIARY FEEDWATER AND CONDENSATE

Auxiliary Feedwater supplies 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 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. Auxiliary Feedwater is described in Unit 1 UFSAR Section 10.5.1 and Unit 2 UFSAR Section 10.4.9.

Condensate includes the condensate storage tank that stores water for use by Auxiliary Feedwater to support safe shutdown of the plant. The condensate storage tanks are cross-connected between the Units. Condensate is described in Unit 1 UFSAR Section 9.2.8 and Unit 2 UFSAR Section 9.2.6.

The flow diagrams listed in Table 2.3-4 show the evaluation boundaries for the portions of Auxiliary Feedwater and Condensate that are within the scope of license renewal.

Auxiliary Feedwater and Condensate 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 design basis events
- SCs that are non-safety related whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires, SBO, and ATWS events

Auxiliary Feedwater and Condensate components subject to an aging management review include tanks, pumps, turbines, and valves (pressure boundary only), coolers, orifices, vortex breakers, sightglasses, piping, tubing, and fittings. The intended functions for Auxiliary Feedwater and Condensate components subject to an aging management review are pressure boundary integrity, heat transfer, vortex prevention, and throttling. For a complete list of Auxiliary Feedwater and Condensate components that require aging management review and the component intended functions, see Table 3.4-3. The aging management review for Auxiliary Feedwater and Condensate is discussed in Section 3.4.

2.3.5 REFERENCES

2.3-1 NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 3, Nuclear Energy Institute, March 2001.

2.3-2 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Nuclear Plant License Renewal Boundary Drawings," L-2001-244.

TABLE 2.3-1
REACTOR COOLANT SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
1-RCS-01	0
1-RCS-02	0
1-RCS-03	0
1-RCS-04	0
1-RCS-05	0
1-RCS-06	0
2-RCS-01	0
2-RCS-02	0
2-RCS-03	0
2-RCS-04	0
2-RCS-05	0
2-RCS-06	0
2-RCS-07	0
2-RCS-08	0
2-RCS-09	0
1-CVCS-02	0
1-CVCS-03	0
2-CVCS-02	0
2-CVCS-04	0
1-FP-05	0
2-PW-01	0
1-SI-03	0
1-SI-04	0
2-SI-03	0
2-SI-04	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-2
ENGINEERED SAFETY FEATURES SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Containment Cooling	
1-HVAC-01	0
2-HVAC-01	0
Containment Spray	
1-CS-01	0
1-CS-02	0
2-CS-01	0
2-CS-02	0
1-SI-01	0
1-SI-02	0
2-SI-02	0
Containment Isolation	
1-HVAC-01	0
2-HVAC-01	0
1-IA-01	0
2-IA-01	0
1-FP-05	0
2-FP-02	0
Safety Injection	
1-SI-01	0
1-SI-02	0
1-SI-03	0
1-SI-04	0
2-SI-01	0
2-SI-02	0
2-SI-03	0
2-SI-04	0
1-CS-01	0
1-CS-02	0
2-CS-01	0
2-CS-02	0
1-CVCS-01	0
1-CVCS-02	0
1-CVCS-03	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-2 (continued)
ENGINEERED SAFETY FEATURES SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Safety Injection (continued)	
2-CVCS-01	0
2-CVCS-04	0
2-RCS-04	0
Containment Post Accident Monitoring	
1-SAMP-02	0
2-SAMP-03	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-3
AUXILIARY SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Chemical and Volume Control	
1-CVCS-01	0
1-CVCS-02	0
1-CVCS-03	0
1-CVCS-04	0
2-CVCS-01	0
2-CVCS-02	0
2-CVCS-03	0
2-CVCS-04	0
1-CS-01	0
2-CS-01	0
1-RCS-03	0
1-RCS-04	0
1-RCS-05	0
1-RCS-06	0
1-SI-03	0
2-SI-02	0
Component Cooling Water	
1-CCW-01	0
1-CCW-02	0
1-CCW-03	0
2-CCW-01	0
2-CCW-02	0
Demineralized Makeup Water	
2-PW-01	0
2-PW-02	0
Diesel Generators and Support Systems	
1-EDG-01	0
1-EDG-02	0
1-EDG-03	0
1-EDG-04	0
1-EDG-05	0
1-EDG-06	0
1-EDG-07	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-3 (continued)
AUXILIARY SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Diesel Generators and Support Systems (continued)	
2-EDG-01	0
2-EDG-02	0
2-EDG-03	0
2-EDG-04	0
2-EDG-05	0
2-EDG-06	0
2-EDG-07	0
Emergency Cooling Canal	
1-ICW-02	0
Fire Protection	
1-FP-01	0
1-FP-02	0
1-FP-03	0
1-FP-04	0
2-FP-01	0
2-FP-02	0
1-CCW-01	0
2-CCW-01	0
Fuel Pool Cooling	
1-SFP-01	0
2-SFP-01	0
Instrument Air	
1-IA-02	0
1-IA-03	0
1-IA-04	0
1-IA-05	0
1-IA-06	0
2-IA-02	0
2-IA-03	0
2-IA-04	0
2-MS-03	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-3 (continued)
AUXILIARY SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Intake Cooling Water	
1-ICW-01	0
2-ICW-01	0
Miscellaneous Bulk Gas Supply	
1-SAMP-02	0
2-SAMP-03	0
2-CS-01	0
2-IA-05	0
Primary Makeup Water	
1-PW-01	0
2-PW-01	0
2-CS-01	0
2-CVCS-03	0
Sampling	
1-SAMP-01	0
2-SAMP-01	0
2-SAMP-02	0
1-CVCS-01	0
2-CVCS-01	0
1-RCS-01	0
1-RCS-02	0
2-RCS-02	0
2-RCS-03	0
2-RCS-04	0
2-SAMP-03	0
1-SI-02	0
1-SI-03	0
1-SI-04	0
2-SI-02	0
2-SI-03	0
2-SI-04	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-3 (continued)
AUXILIARY SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Service Water	
1-FP-01	0
1-FP-02	0
2-FP-01	0
Turbine Cooling Water	
1-TCW-01	0
Ventilation	
1-HVAC-01	0
1-HVAC-02	0
2-HVAC-01	0
2-HVAC-02	0
2-HVAC-03	0
Waste Management	
1-WM-01	0
1-WM-02	0
1-WM-03	0
2-WM-01	0
2-WM-02	0
2-WM-03	0
1-CS-01	0
2-CS-01	0
2-FP-01	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

TABLE 2.3-4
STEAM AND POWER CONVERSION SYSTEMS
LICENSE RENEWAL BOUNDARY DRAWINGS[1]

Drawing Number	Revision
Main Steam, Auxiliary Steam, and Turbine	
1-MS-01	0
1-MS-02	0
1-MS-03	0
1-MS-04	0
2-MS-01	0
2-MS-02	0
2-MS-03	0
1-AFW-02	0
2-AFW-02	0
1-IA-05	0
Main Feedwater and Steam Generator Blowdown	
1-FW-01	0
1-FW-02	0
2-FW-01	0
1-AFW-02	0
2-AFW-02	0
1-EDG-01	0
2-EDG-01	0
1-MS-01	0
2-MS-01	0
1-SGBD-01	0
2-SGBD-01	0
Auxiliary Feedwater and Condensate	
1-AFW-01	0
1-AFW-02	0
2-AFW-01	0
2-AFW-02	0

NOTE: 1. Drawings submitted separately [Reference 2.3-2].

2.4 SCOPING AND SCREENING RESULTS - STRUCTURES

The determination of structures within the scope of license renewal is made by initially identifying St. Lucie Units 1 and 2 structures and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1 and results of the civil/structural review are contained in Section 2.2.

Section 2.1 also provides the methodology for determining the components within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The structural components that meet these screening requirements are identified in this section. These identified structural components subsequently require an aging management review for license renewal.

The screening results are provided below in two subsections:

- Containments
- Other Structures

2.4.1 CONTAINMENTS

Each St. Lucie Containment consists of the freestanding steel Containment Vessel surrounded by the Reactor Containment Shield Building. The Containments house the Reactor Coolant Systems, Reactor Coolant System supports, and other important systems that interface with the Reactor Coolant Systems. 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 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 Reactor Coolant System.

The St. Lucie Unit 1 UFSAR and the Unit 2 UFSAR classify each Containment as a seismic category 1 structure designed to prevent the uncontrolled release of radioactivity. Seismic category 1 structures have been determined to meet the criteria of 10 CFR 54.4 and are within the scope of license renewal. For screening, each Containment has been divided into three structural categories, Containment Vessel, Reactor Containment Shield Building, and Reactor Containment Shield Building Interior Components. Each structural category was then subdivided into component/commodity groups to determine those structures and structural components requiring an aging management review. The component/commodity groups were developed based on a review of St. Lucie plant-controlled drawings, each Unit's UFSAR, the plant equipment database, guidance from NEI 95-10 [Reference 2.4-1] and the GALL Report [Reference 2.4-2].

Containment structural components requiring an aging management review are identified in the following subsections. Note that the discussions below apply to the Containments for both Units 1 and 2.

2.4.1.1 CONTAINMENT VESSELS

Each Containment Vessel houses the reactor pressure vessel, the reactor coolant piping and pumps, the steam generators, the pressurizer and pressurizer quench tank, and other branch connections of the Reactor Coolant System, including the safety injection tanks. The containment penetration assemblies provide for passage of process, service, sampling, and instrumentation piping and electrical cabling into the Containment Vessel while maintaining containment integrity and providing a leak-tight seal. Note that attachments to the Containment Vessel are in the scope of license renewal. Steel substructures are described below.

2.4.1.1.1 CONTAINMENT VESSELS

Each Containment Vessel is a low leakage steel shell, including all penetrations, designed to confine radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary. Each Containment Vessel is a right circular cylinder with a hemispherical dome and an ellipsoidal bottom. The Containment Vessels are described in Unit 1 UFSAR Section 3.8.2 and Unit 2 UFSAR Section 3.8.2.

2.4.1.1.2 MECHANICAL PENETRATIONS

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. The mechanical penetrations are described in Unit 1 UFSAR Section 3.8.2.1.10 and Unit 2 UFSAR Section 3.8.2.1.1.1.

2.4.1.1.3 ELECTRICAL PENETRATIONS

Canister or header plate type penetration assemblies are used for all electrical conductors through the Containment Vessel, annulus, and Reactor Containment Shield Building. 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. Electrical penetrations are described in Unit 1 UFSAR Section 3.8.2.1.10 and Unit 2 UFSAR Section 3.8.2.1.1.2.

2.4.1.1.4 AIRLOCKS AND HATCHES

Two equipment hatches are provided for each Containment Vessel, a construction hatch and a maintenance hatch. 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.

2.4.1.1.5 FUEL TRANSFER TUBES

The fuel transfer tubes, one for each Unit, are provided to transfer fuel assemblies between the refueling cavity in each Containment and the spent fuel pool in the Fuel Handling Buildings during refueling operations. Each of the penetrations 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. The fuel transfer tubes are described in Unit 1 UFSAR Section 3.8.2.1.10 and Unit 2 UFSAR Section 3.8.2.1.1.1.

2.4.1.2 REACTOR CONTAINMENT SHIELD BUILDINGS

Each Reactor Containment Shield Building is a low-leakage concrete structure that surrounds the steel Containment Vessel. Each 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 a hypothetical accident, and provides environmental protection for the Containment Vessel.

Each 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 Buildings are described in Unit 1 UFSAR Section 3.8.2.2.1 and Unit 2 UFSAR Section 3.8.4.1.1.

Each Containment Vessel and Reactor Containment Shield Building is 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.

2.4.1.3 REACTOR CONTAINMENT SHIELD BUILDING INTERIOR COMPONENTS

The interior structures of each Containment Vessel and Reactor Containment Shield Building 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 Reactor Coolant System 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 Reactor Coolant System 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. The Reactor Containment Shield Building internal components are described in Unit 1 UFSAR Section 3.8.3 and Unit 2 UFSAR Section 3.8.3.

2.4.1.3.1 CONCRETE

The shield walls are thick cylindrical 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.

Barriers surround all high-pressure equipment, i.e., high-energy reactor coolant system piping and components, which could generate missiles as a result of a design basis accident. These barriers, principally the primary and secondary shield walls, prevent such missiles from damaging the Containment Vessel, piping penetrations, and the required engineered safety features systems.

Concrete walls, floors, beams, equipment pads, and other miscellaneous concrete components are of conventional reinforced concrete design.

2.4.1.3.2 STEEL

Reactor Cavity Sumps

The floors and walls of each reactor cavity are lined with stainless steel. The floor is sloped to drain all leakage to the reactor cavity sump. Each 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 Emergency Core Cooling Systems.

Reactor Coolant System Supports

Reactor Coolant System supports that are subject to an aging management review include the reactor vessel supports, steam generator supports, pressurizer supports, and reactor coolant pump supports. The Reactor Coolant System supports are designed to resist operating loads, pipe ruptures, and seismic loads.

The Reactor Coolant System support boundaries in scope and subject to an aging management review include all structural support items between the Reactor Coolant System components and the Containment concrete structure, up to and including, integral attachments that are on Reactor Coolant System components. The integral attachments on the components are reviewed with the components and the concrete structure is reviewed with the Containment structure.

Miscellaneous Steel and Component Supports

Structural and miscellaneous steel are provided in each Containment to allow access to the various elevations and areas for inspection and maintenance. The 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.

2.4.1.4 CONCLUSION

The Containments are in the scope of license renewal because they:

- Provide 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 components whose failure could prevent satisfactory accomplishment of any of the required safety-related functions
- 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

A complete list of Containment structural components requiring an aging management review and the component intended functions are provided in Table 3.5-2. The aging management review of the Containments is discussed in Section 3.5.1.

2.4.2 OTHER STRUCTURES

The following structures are included in this subsection:

- 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

2.4.2.1 COMPONENT COOLING WATER AREAS

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 1 Component Cooling Water Area is described in Unit 1 UFSAR Section 9.2.2 and Appendix 9.5A.

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 Unit 2 Component Cooling Water Area is described in Unit 2 UFSAR Section 3.4.

The Component Cooling Water Areas are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide flood protection barriers
- Provide structural support and/or shelter to components required for FP

A complete list of Component Cooling Water Areas structural components requiring an aging management review and the component intended functions are provided in Table 3.5-3. The aging management review for the Component Cooling Water Areas is discussed in Subsection 3.5.2.

2.4.2.2 CONDENSATE POLISHER BUILDING

The Condensate Polisher Building is designated as Fire Zone 15A, and consists of a reinforced concrete building that contains various equipment including Fire Protection equipment and components. The Condensate Polisher Building is described in Unit 1 UFSAR Appendix 9.5A, Section 4.0.

The Condensate Polisher Building is in the scope of license renewal because it:

- Provides structural support and/or shelter to components required for FP

A complete list of Condensate Polisher Building structural components requiring an aging management review and the component intended functions are provided in Table 3.5-4. The aging management review for the Condensate Polisher Building is discussed in Subsection 3.5.2.

2.4.2.3 CONDENSATE STORAGE TANK ENCLOSURES

The Unit 1 and Unit 2 Condensate Storage Tank Enclosures are cylindrical reinforced concrete structures designed to seismic category 1 requirements and are used primarily for horizontal tornado missile protection of the tanks.

The Unit 1 Condensate Storage Tank Enclosure is 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. The Unit 1 Condensate Storage Tank Enclosure is described in Unit 1 UFSAR Section 3.5.4.2, Appendix 3F, Section 4.3.5, and Appendix 9.5A.

The Unit 2 Condensate Storage Tank Enclosure is equipped with a precast concrete dome roof overlaid with reinforced concrete that provides vertical missile protection. The structure is supported on a reinforced concrete base mat. The Unit 2 Condensate Storage Tank Enclosure is described in Unit 2 UFSAR Section 3.8.4.1.7 and Appendix 9.5A.

The steel condensate storage tanks 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.

The Condensate Storage Tank Enclosures are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide structural support and/or shelter to components required for FP and/or SBO

A complete list of Condensate Storage Tank Enclosure structural components requiring an aging management review and the component intended functions are provided in Table 3.5-5. The aging management review for the Condensate Storage Tank Enclosures is discussed in Subsection 3.5.2.

2.4.2.4 DIESEL OIL EQUIPMENT ENCLOSURES

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 an overflow/rupture reinforced concrete containment wall. The Unit 1 Diesel Oil Equipment Enclosures are described in Unit 1 UFSAR Section 9.5.4.

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. The Unit 2 Diesel Oil Equipment Enclosure is described in Unit 2 UFSAR Section 9.5.4.

The Diesel Oil Equipment Enclosures are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide flood protection barriers
- Provide structural support and/or shelter to components required for FP and/or SBO (Unit 2 Enclosure for a Unit 1 SBO)

A complete list of Diesel Oil Equipment Enclosure structural components requiring an aging management review and the component intended functions are provided in Table 3.5-6. The aging management review for the Diesel Oil Equipment Enclosures is discussed in Subsection 3.5.2.

2.4.2.5 EMERGENCY DIESEL GENERATOR BUILDINGS

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 Emergency Diesel Generator Buildings are described in Unit 1 UFSAR Sections 3.8.1.1.3, 3.8.1.7.4, 8.3, 9.4.7, and 9.5, and Unit 2 UFSAR Sections 3.8.4.1.4, 8.3, 9.4.5, and 9.5.

The Emergency Diesel Generator Buildings are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide flood protection barriers
- Provide structural support and/or shelter to components required for FP and/or SBO

A complete list of Emergency Diesel Generator Building structural components requiring an aging management review and the component intended functions are provided in Table 3.5-7. The aging management review for the Emergency Diesel Generator Buildings is discussed in Subsection 3.5.2.

2.4.2.6 FIRE RATED ASSEMBLIES

Fire rated assemblies include: fire barriers, fire doors, fire dampers, and penetration seals. The fire rated assemblies are described in Unit 1 UFSAR Appendix 9.5A, Sections 3.11 through 3.14, and Unit 2 UFSAR Appendix 9.5A, Sections 3.11 through 3.14.

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 Subsection 2.3.3.15.

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 heating, ventilation and air conditioning (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.

Fire rated assemblies are in the scope of license renewal because they:

- Provide pressure boundary (Halon for Unit 1 cable spreading room)
- Provide fire barriers to retard spreading of a fire
- Provide flood protection barriers
- Provide boundary for safety related ventilation

A complete list of fire rated assemblies structural components requiring an aging management review and the component intended functions are provided in Table 3.5-8. The aging management review for the fire rated assemblies is discussed in Subsection 3.5.2.

2.4.2.7 FUEL HANDLING BUILDINGS

Each Fuel Handling Building is a seismic category 1 reinforced concrete structure. Each spent fuel pool is a stainless steel lined, reinforced concrete tank structure within the Fuel Handling Building and provides space for the storage of spent fuel, spent fuel casks, and miscellaneous items. The remainder of each Fuel Handling Building consists of concrete exterior walls with reinforced concrete interior walls. The floor and roof for each Fuel Handling Building are of beam and girder construction supported by columns. The Fuel Handling Buildings are described in Unit 1 UFSAR Section 3.8.1.1.2 and Unit 2 UFSAR Section 3.8.4.1.3.

The Fuel Handling Buildings are in the scope of license renewal because they:

- Provide pressure boundary
- 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 any of the required safety-related functions
- Provide flood protection barriers
- Provide a boundary for safety-related ventilation

A complete list of Fuel Handling Building structural components requiring an aging management review and the component intended functions are provided in Table 3.5-9. The aging management review for the Fuel Handling Buildings is discussed in Subsection 3.5.2.

2.4.2.8 FUEL HANDLING EQUIPMENT

The fuel handling equipment is an integrated system of equipment for refueling the reactor. The system provides for handling and storage of fuel assemblies from receipt of new fuel to shipping of spent fuel. 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 described in Unit 1 UFSAR Section 9.1 and Unit 2 UFSAR Section 9.1.

Fuel handling equipment is located in the Containments or the Fuel Handling Buildings. Fuel handling equipment is evaluated with the structure where it is located.

2.4.2.9 INTAKE, DISCHARGE, AND EMERGENCY COOLING CANALS

The Intake Canal, which takes water directly from the Atlantic Ocean through subaqueous intake water pipes that run under the beach and terminate at the intake canal headwalls, serves as the plant heat sink. In the unlikely event of blockage of the Intake Canal or pipes, emergency cooling water will be taken from Big Mud Creek through the Emergency Cooling Canal. This emergency source of water is designed to withstand design basis seismic, tornado, and hurricane conditions. Regardless of the source, cooling water is discharged into the Discharge Canal, and then flows to the Atlantic Ocean through discharge pipes. The Intake, Discharge and Emergency Cooling Canals are described in Unit 1 UFSAR Section 2.4.9 and Unit 2 UFSAR Section 2.4.9.

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 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 Discharge Canal and most of the Intake Canal are not in the scope of license renewal because they do not perform an intended function. The Emergency Cooling Canal and the portion of the Intake Canal between the Emergency Cooling Canal and the Intake Structure (see Figure 2.2-2) are in the scope of license renewal because they:

- Provide a source of cooling water for plant shutdown
- Provide structural support and/or shelter to components required for FP

A complete list of Intake, Discharge, and Emergency Cooling Canal structural components requiring an aging management review and the component intended functions are provided in Table 3.5-10. The aging management review for the Intake, Discharge, and Emergency Cooling Canals is discussed in Subsection 3.5.2.

2.4.2.10 INTAKE STRUCTURES

The Intake Structures are seismic category 1 reinforced concrete structures containing the circulating water pumps and intake cooling water pumps. Each Intake Structure consists of a base mat, exterior walls braced internally to the bay walls, and an operating deck. Water enters 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 Intake Structures are described in Unit 1 UFSAR Sections 2.4.8 and 3.8.1.1.4, and Unit 2 UFSAR Section 3.8.4.1.5.

The Intake Structures are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide structural support and/or shelter to components required for FP

A complete list of Intake Structure structural components requiring an aging management review and the component intended functions are provided in Table 3.5-11. The aging management review for the Intake Structures is discussed in Subsection 3.5.2.

2.4.2.11 REACTOR AUXILIARY BUILDINGS

The Reactor Auxiliary Buildings 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 Reactor Auxiliary Buildings are described in Unit 1 UFSAR Section 3.8.1.1.1 and Unit 2 UFSAR Section 3.8.4.1.2.

The Reactor Auxiliary Buildings are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- 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

A complete list of Reactor Auxiliary Building structural components requiring an aging management review and the component intended functions are provided in Table 3.5-12. The aging management review for the Reactor Auxiliary Buildings is discussed in Subsection 3.5.2.

2.4.2.12 STEAM TRESTLE AREAS

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 Building and Turbine Building. The Steam Trestle Areas are described in Unit 1 UFSAR Appendix 3C and Unit 2 UFSAR Section 3.8.4.1.9.

The Steam Trestle Areas are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide structural support and/or shelter to components required for FP and/or SBO
- Provide pipe whip restraint and/or jet impingement protection

A complete list of Steam Trestle Area structural components requiring an aging management review and the component intended functions are provided in Table 3.5-13. The aging management review for the Steam Trestle Areas is discussed in Subsection 3.5.2.

2.4.2.13 TURBINE BUILDINGS

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 described in Unit 1 UFSAR Section 3.8.4.1 and Unit 2 UFSAR Section 3.8.4.1.12.

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 (feedwater 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 Turbine Buildings are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide missile barriers
- Provide structural support and/or shelter to components required for FP, ATWS, and/or SBO

A complete list of Turbine Building structural components requiring an aging management review and the component intended functions are provided in Table 3.5-14. The aging management review for the Turbine Buildings is discussed in Subsection 3.5.2.

2.4.2.14 ULTIMATE HEAT SINK DAM

The Ultimate Heat Sink Dam is a seismic category 1 reinforced concrete retaining wall that extends across the Emergency Cooling Canal. The main structure of the Ultimate Heat Sink Dam consists of the concrete barrier wall, the perpendicular concrete buttresses, the concrete mat foundation, and the equipment rooms. The function of the Ultimate Heat Sink Dam is to separate the waters of Big Mud Creek from the Intake Canal during normal operation, and to provide a safety related source of cooling water through valved openings, which are screened in Subsection 2.3.3.5, in the unlikely event that the ocean intake becomes unavailable. The Ultimate Heat Sink Dam is described in Unit 1 UFSAR Sections 3.8.1.1.5, 3.8.1.7.5, and 9.2.7 and Unit 2 UFSAR Section 9.2.5.

The Ultimate Heat Sink Dam is in the scope of license renewal because it:

- Provides structural support to safety-related components
- Provides shelter/protection to safety-related components
- Provides missile barriers
- Provides structural support to non-safety related components whose failure could prevent satisfactory accomplishment of any of the required safety-related functions

A complete list of Ultimate Heat Sink Dam structural components requiring an aging management review and the component intended functions are provided in Table 3.5-15. The aging management review for the Ultimate Heat Sink Dam is discussed in Subsection 3.5.2.

2.4.2.15 YARD STRUCTURES

Yard Structures includes 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 Yard Structures are described in Unit 1 UFSAR Sections 2.4.5.3.2 and 8.3.1.1.9.

The Yard Structures are in the scope of license renewal because they:

- 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 any of the required safety-related functions
- Provide flood protection barriers
- Provide structural support and/or shelter to components required for FP and/or SBO

A complete list of Yard Structures structural components requiring an aging management review and the component intended functions are provided in Table 3.5-16. The aging management review for the Yard Structures is discussed in Subsection 3.5.2.

2.4.3 REFERENCES

2.4-1 NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 3, Nuclear Energy Institute, March 2001.

2.4-2 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

2.5 SCOPING AND SCREENING RESULTS - ELECTRICAL AND INSTRUMENTATION AND CONTROLS (I&C) SYSTEMS

The methodology used in identifying electrical/I&C components requiring an aging management review is discussed in Section 2.1.2.3. The screening for electrical/I&C components was performed on a generic component commodity group basis for the in-scope electrical/I&C systems listed in Table 2.2-3, as well as the electrical/I&C component commodity groups associated with in-scope mechanical systems and civil structures listed in Tables 2.2-1 and 2.2-2. The methodology employed is consistent with the guidance in NEI 95-10 [Reference 2.5-1].

The interface of electrical/I&C components with other types of components and the assessments of these interfacing components are provided in the appropriate mechanical or civil/structural sections. For example, the assessment of electrical racks, panels, frames, cabinets, cable trays, conduit, and their supports is provided in the civil/structural assessment documented in Sections 2.4 and 3.5.

The electrical/I&C components included in the screening were the separate electrical/I&C components that were not parts of larger components. For example, the wiring, terminal blocks, and connections located internal to a breaker cubicle were considered to be parts of the breaker. Accordingly, the breaker was screened, but not the internal parts.

2.5.1 ELECTRICAL/I&C COMPONENT COMMODITY GROUPS

The electrical/I&C component commodity groups were identified from a review of controlled drawings, the plant equipment database, and interface with the parallel mechanical and civil/structural screening efforts. The in-scope electrical/I&C component commodity groups identified at St. Lucie Units 1 and 2 are listed in Table 2.5-1. This list includes all electrical/I&C component commodity groups listed in Appendix B of NEI 95-10 [Reference 2.5-1], with the exception of the following component commodity groups that were eliminated from consideration based on plant-level scoping:

- **Electrical Buses** - The isolated-phase buses and switchyard buses are not relied on to meet the license renewal scoping requirements of 10 CFR 54.4(a).
- **Transmission Conductors** - Transmission conductors are not relied on to meet the license renewal scoping requirements of 10 CFR 54.4(a).
- **High Voltage Insulators** - High-voltage insulators are not relied on to meet the license renewal scoping requirements of 10 CFR 54.4(a).

No additional component commodity groups, beyond those listed in Appendix B of NEI 95-10, were identified.

2.5.2 APPLICATION OF SCREENING CRITERION 10 CFR 54.21(a)(1)(i) TO ELECTRICAL/I&C COMPONENT COMMODITY GROUPS

Following the identification of the electrical/I&C component commodity groups, the criterion of 10 CFR 54.21(a)(1)(i) was applied to identify component commodity groups that perform their intended function passively. This evaluation was performed utilizing the guidance of 10 CFR 54.21(a)(1)(i) and NEI 95-10 [Reference 2.5-1].

The following electrical/I&C component commodity groups were determined to meet the screening criterion of 10 CFR 54.21(a)(1)(i) and were further evaluated against the criterion of 10 CFR 54.21(a)(1)(ii):

- Cables and Connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks); and
- Electrical/I&C Penetration Assemblies (electrical portions).

2.5.3 APPLICATION OF SCREENING CRITERION 10 CFR 54.21(a)(1)(ii) TO SPECIFIC ELECTRICAL/I&C COMPONENT COMMODITY GROUPS

Title 10 CFR, Section 54.21(a)(1)(ii) allows the exclusion of those component commodity groups that are subject to replacement based on a qualified life or specified time period. The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to the specific component commodity groups that were not eliminated by application of the 10 CFR 54.21(a)(1)(i) screening criterion. The results of this review are discussed below.

2.5.3.1 CABLES AND CONNECTIONS

The function of cables and connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables and their required terminations (i.e., connections) are reviewed as a single component commodity group. The types of connections in this review include splices, connectors, and terminal blocks.

Numerous cables and connections are included in the St. Lucie Environmental Qualification Program. Cables and connections included in this program have a documented qualified life and are replaced by the end of that qualified life. Accordingly, these cables and connections are not subject to an aging management review per 10 CFR 54.21(a)(1)(ii). Note that time-limited aging analyses (TLAAs) associated with electrical/I&C components within the Environmental Qualification Program are discussed in Subsection 4.4.1.

Cables and connections that perform a license renewal intended function and are not included in the Environmental Qualification Program meet the criterion of 10 CFR 54.21(a)(1)(ii) and are thus subject to an aging management review.

2.5.3.2 ELECTRICAL/I&C PENETRATION ASSEMBLIES (ELECTRICAL PORTIONS)

All of the electrical/I&C penetration assemblies in the scope of license renewal are included in the St. Lucie Environmental Qualification Program. As such, these components have a qualified life that is described in program documents and, per 10 CFR 54.21(a)(1)(ii), they are not subject to an aging management review.

2.5.4 ELECTRICAL/I&C COMPONENTS REQUIRING AN AGING MANAGEMENT REVIEW

The electrical/I&C component commodity groups subject to an aging management review are:

- Cables and Connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks) not included in the Environmental Qualification Program.

The intended function for the electrical/I&C component commodity groups subject to an aging management review is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. A more detailed list of the electrical/I&C component commodity groups requiring an aging management review and the component commodity group intended functions are provided in Table 3.6-5. The aging management review for electrical/I&C component commodity groups is discussed in Section 3.6.

2.5.5 REFERENCES

2.5-1 NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 3, Nuclear Energy Institute, March 2001.

TABLE 2.5-1
ELECTRICAL/I&C COMPONENT COMMODITY GROUPS

<table>
<tr><th colspan="4">ELECTRICAL/I&C COMPONENT COMMODITY GROUPS INSTALLED AT ST. LUCIE FOR IN-SCOPE SYSTEMS AND STRUCTURES</th></tr>
<tr><td>Alarm Units
(including fire detectors)</td><td>Circuit Breakers</td><td>Fuses</td><td>Signal Conditioners</td></tr>
<tr><td>Analyzers</td><td rowspan="2">Communication Equipment</td><td>Generators, Motors</td><td>Solenoid Operators</td></tr>
<tr><td>Annunciators</td><td rowspan="2">High voltage Surge Arrestors</td><td>Solid-state Devices</td></tr>
<tr><td>Batteries</td><td rowspan="5">Electric Heaters, Heat Tracing</td><td rowspan="2">Switches</td></tr>
<tr><td rowspan="4">Cables/Connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks), Bus, Electrical Portions of Electrical/ I&C Penetration Assemblies</td><td>Indicators</td></tr>
<tr><td>Isolators</td><td rowspan="3">Internal Component Assemblies for Switchgears, Load Centers, Motor Control Centers, and Distribution Panels</td></tr>
<tr><td>Light Bulbs</td></tr>
<tr><td>Loop Controllers</td></tr>
<tr><td rowspan="6">Chargers, Converters, Inverters</td><td rowspan="3">Electrical/I&C Controls and Panel Internal Component Assemblies</td><td>Meters</td><td rowspan="2">Transformers</td></tr>
<tr><td>Power Supplies</td></tr>
<tr><td>Radiation Monitors</td><td rowspan="4">Transmitters</td></tr>
<tr><td rowspan="3">Elements, Resistance Temperature Detectors (RTDs), Sensors, Thermocouples, Transducers</td><td>Recorders</td></tr>
<tr><td>Regulators</td></tr>
<tr><td>Relays</td></tr>
</table>

3.0 AGING MANAGEMENT REVIEW RESULTS

For those structures and components that are identified as being subject to an aging management review, 10 CFR 54.21(a)(3) requires demonstration that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The information provided in this chapter provides essential input to the required aging management review as this chapter identifies and discusses the aging effects requiring management.

This chapter describes the results of the aging management reviews of the components and structures identified in Chapter 2, "Structures and Components Subject to an Aging Management Review." This chapter:

- provides references to the descriptions of common aging management programs
- identifies the components and structural components subject to aging management review, and their intended functions
- discusses the materials and internal and external environments
- describes or references the processes used to identify aging effects
- describes industry and plant-specific operating experiences with respect to the aging effects
- identifies the aging effects requiring management
- lists the aging management programs for aging effects requiring management

For those structures and components identified as being subject to an aging management review, the results are contained in Section 3.1, "Reactor Coolant Systems," 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" (Subsection 3.5.1 for Containments and Subsection 3.5.2 for Other Structures), and Section 3.6, "Electrical and Instrumentation and Controls." Aging management program descriptions are contained in Appendix B.

Tables 3.0-1 and 3.0-2 contain descriptions of the internal and external service environments at St. Lucie Nuclear Plant that will be used in subsequent sections of this chapter. The environments used in the aging management reviews are listed in the "Environment" column in Tables 3.0-1 and 3.0-2. Within this application, some of the internal environments have been subdivided into groups based on the fluid chemistry. The subgroups are identified in the "Description" column in Table 3.0-1.

TABLE 3.0-1
INTERNAL SERVICE ENVIRONMENTS

Environment	Description
Air/Gas	Includes atmospheric air, dry/filtered instrument air and diesel starting air, nitrogen, hydrogen, carbon dioxide, and Halon. Instrument air upstream of the air dryers is annotated as "wetted."
Treated water	Base water for all clean systems. Demineralized water that can be deaerated, or include corrosion inhibitors, biocides, and boric acid, or any combination of these treatments. Within this application, treated water has been subdivided into groups based on the chemistry of the water: Treated water – primary – Normal operating Reactor Coolant System chemistry. Treated water – secondary – Normal operating secondary chemistry, including Main Steam, Main Feedwater, and Steam Generator Blowdown Systems. Treated water – borated – Systems that contain borated water except those included in treated water – primary, including Chemical and Volume Control, Spent Fuel Cooling, and Safety Injection Systems. Treated water – other – All other treated water systems, including Component Cooling Water, Diesel Generator Cooling Water, and Auxiliary Feedwater Systems.
Raw water	Water that enters the plant from the ocean, Big Mud Creek, or a city water source that has not been demineralized. In general, all raw water sources have been rough filtered to remove large particles and may contain a biocide for control of micro-organisms and macro-organisms. Although city water is purified for drinking purposes, it is conservatively classified as raw water for the purposes of aging management review. Within this application, raw water has been subdivided into groups based on the chemistry of the water: Raw water – salt water – Salt water used as the ultimate heat sink. Raw water – city water – Potable water supplied to the Fire Protection System and Service Water Systems. Raw water – drains – Fluids collected in building drains. The fluids can be treated water (primary, secondary, borated, or other), raw water (salt or city water), fuel oil, or lubricating oil.
Fuel oil	Emergency diesel generator fuel oil.
Lubricating oil	Lubricating oil for emergency diesel generators, pumps, and other components. Also includes hydraulic oils used in hydraulic valve actuators.
Ohmic heating	Thermal stress on power cable materials can be due to ohmic heating resulting from electrical current.

TABLE 3.0-2
EXTERNAL SERVICE ENVIRONMENTS

Environment[1]	Description
Outdoor[2]	Moist, salt-laden atmospheric air, temperature 27°F -93°F, 73% average humidity, exposed to weather, including precipitation and wind.
Indoor – not air conditioned[2]	Atmospheric air, maximum temperature 104°F (110°F for Unit 2 electrical equipment room), 73% average humidity, not exposed to weather.
Indoor – air conditioned[2]	Atmospheric air, temperature 70°F -80°F, humidity 45%-55%, not exposed to weather
Containment air[2]	Atmospheric air, maximum temperature 120°F, 73% average humidity, total integrated dose rate 2 rad/hour (excluding equipment located inside the reactor cavity), not exposed to weather.
Borated water leaks	Exposed to leakage from borated water systems.
Buried	Above groundwater elevation, exposed to soil/fill. Below groundwater elevation, exposed to soil/fill and groundwater.
Embedded/encased	Embedded or encased steel or piping in concrete.

NOTES:
1. For certain components and structural components that are submerged, the applicable environment in Table 3.0-1 is specified.
2. Where wetted conditions exist (e.g., condensation), the item is annotated [e.g., Indoor – not air conditioned (wetted)] in Chapter 3.

3.1 REACTOR COOLANT SYSTEMS

Reactor Coolant Systems components within the scope of license renewal that require aging management review are identified in Subsection 2.3.1. The following Reactor Coolant System mechanical components are included in this section:

- Reactor Coolant Piping
- Pressurizers
- Reactor Vessels (includes pressure boundary of control element drive mechanisms)
- Reactor Vessel Internals
- Reactor Coolant Pumps
- Steam Generators

Determination of the aging effects related to Reactor Coolant Systems components begins with identification of aging effects defined in industry literature. From this set of aging effects, the materials, operating environments, and operating stresses define the aging effects requiring management for each component that is subject to an aging management review. Aging effects requiring management are then validated by a review of industry and St. Lucie Units 1 and 2 operating experience to provide assurance that all aging effects requiring management are identified.

The determination of aging effects requiring management considers the materials, environments, and stresses of St. Lucie Units 1 and 2 components. The aging effects requiring management for the Reactor Coolant Systems components are discussed in the following subsections.

The only areas inaccessible for inspection for the Reactor Coolant Systems are a limited number of locations internal to certain components (i.e., pressurizers, reactor vessel internals, and steam generators). Aging effects associated with these areas are addressed as part of the aging management review discussions in Subsections 3.1.2, 3.1.4, and 3.1.6 respectively.

3.1.1 REACTOR COOLANT PIPING

Reactor coolant piping consists of Class 1 and non-Class 1 components. The aging management review results for Class 1 reactor coolant piping components are discussed in Subsection 3.1.1.1, and non-Class 1 reactor coolant piping components are discussed in Subsection 3.1.1.2.

The reactor coolant piping scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Connected systems piping and fittings - Core Flood System (IV C2.2.2) - The St. Lucie design does not include these components.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsections 3.1.1.1.1 and 3.1.1.2.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsections 3.1.1.1.4 and 3.1.1.2.4, and are detailed in the appropriate subsections of Appendix B. Reactor coolant piping component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.1.1 CLASS 1 PIPING

Class 1 reactor coolant piping components are within the scope of license renewal as discussed in Subsection 2.3.1.1.1. Class 1 reactor coolant piping components that are subject to an aging management review are listed in Table 3.1-1.

3.1.1.1.1 MATERIALS AND ENVIRONMENTS

Class 1 reactor coolant piping components are exposed to an internal environment of treated water - primary and external environments of containment air and potential borated water leaks (see Tables 3.0-1 and 3.0-2).

Class 1 reactor coolant piping components are constructed of stainless steel, cast stainless steel, Alloy 600, Alloy 690, ENiCrFe-3 (weld material), carbon steel, and low alloy steel. The Class 1 reactor coolant piping components, their intended functions, the materials, and environments are listed in Table 3.1-1. For the corresponding component/commodity group nozzles included in the GALL Report, FPL identified carbon steel with stainless steel cladding as an additional material.

3.1.1.1.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of material
- Loss of mechanical closure integrity

CRACKING

Cracking due to flaw growth and stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Subsection 4.3.1.

Growth of original manufacturing flaws over time due to service loading can cause cracking. Detection and evaluation of flaws is important in maintaining the structural integrity of the Class 1 pressure boundary. ASME Section XI inservice examinations of components are intended to detect significant flaw growth and development. These examinations provide assurance that significant flaws do not exist, or a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired, if necessary. In order to confirm that cracking is not occurring in small bore (<4 inches in diameter) Class 1 reactor coolant piping, a one-time inspection to complement present ASME Section XI examinations will be performed. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, supplemented by the one-time Small Bore Class 1 Piping Inspection, provides assurance that flaw growth is managed and that the intended function of Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from Class 1 reactor coolant piping components. In addition, to reduce the susceptibility of Class 1 reactor coolant piping materials to stress corrosion cracking, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the Class 1 reactor coolant piping is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Industry and plant-specific experience has identified Alloy 600 as susceptible to cracking in a primary water environment. This aging mechanism is called primary water stress corrosion cracking (PWSCC). Therefore, Alloy 600 fittings, instrument nozzles, and thermowells, and the ENiCrFe-3 utilized as a welding filler metal for dissimilar metal welds can crack due to PWSCC even though the water chemistry is controlled within plant requirements. Chemistry control helps to minimize the contaminants that cause PWSCC but it is not adequate by itself since industry and plant failures have occurred. The Alloy 600 Inspection Program, in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that PWSCC is managed and that the intended function of Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

REDUCTION IN FRACTURE TOUGHNESS

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 microstructure and properties of a material due to exposure to elevated temperatures for an extended period. The only Class 1 reactor coolant piping components subject to reduction in fracture toughness due to thermal embrittlement are austenitic stainless steel castings. Cast austenitic stainless steel Class 1 reactor coolant piping components at St. Lucie Units 1 and 2 consist of selected valves, piping, fittings, and safe ends. Reduction in fracture toughness of the pressurizer surge nozzle safe ends is discussed in Subsection 3.1.2, and the reduction in fracture toughness of the reactor coolant pump casings and covers is discussed in Subsection 3.1.5.

The reduction in fracture toughness of cast austenitic stainless steel (i.e., CASS) primary piping, fittings, and safe ends is a relevant aging effect that requires management. The Thermal Aging Embrittlement of CASS Program provides assurance that reduction in fracture toughness due to thermal aging is managed and that the intended function of the Class 1 cast austenitic stainless steel piping, fittings, and safe ends is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Screening of Class 1 cast austenitic stainless steel valves for susceptibility to thermal embrittlement is not required during the period of extended operation [Reference 3.1-2]. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that reduction in fracture toughness due to thermal aging is managed and that the intended function of the Class 1 cast austenitic stainless steel valves is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

LOSS OF MATERIAL

Loss of material due to aggressive chemical attack is an aging effect requiring management for external surfaces of carbon steel Class 1 reactor coolant piping components exposed to borated water leaks. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of material due to aggressive chemical attack is managed and that the intended function of the Class 1 reactor coolant piping is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack.

Loss of mechanical closure integrity due to stress relaxation is a relevant aging effect that requires management. This aging effect can be managed by periodic inservice inspections and leakage testing. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that loss of mechanical closure integrity due to stress relaxation is managed and that the intended function of Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

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. Mechanical closure bolting associated with Class 1 reactor coolant piping components is made of low alloy steel bolting material and is subject to aggressive chemical attack from potential borated water leaks. 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 function of Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

The GALL Report identifies stress corrosion cracking of low alloy steel bolting materials as an aging effect that requires management. High stress in conjunction with an aggressive environment can cause cracking of certain bolting materials due to stress corrosion cracking (SCC). As identified in NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," and Generic Letter 91-17, "Generic Safety Issue 29, Bolting Degradation or Failure in Nuclear Power Plants," cracking of bolting due to SCC has occurred in the nuclear industry. These instances of SCC have been primarily attributed to the use of high-yield strength bolting materials, excessive torquing of fasteners, and contaminants, such as the use of lubricants containing molybdenum disulfide (MoS_2). In response to NRC IE Bulletin 82-02, FPL verified that:

- Specific maintenance procedures were in place at St. Lucie Units 1 and 2 to address bolted closures.
- The procedures in use addressed detensioning and retensioning practices and gasket installation and controls.
- Threaded fastener lubricants used in pressure boundary applications have specified maximum allowable limits for chloride and sulfur content to minimize susceptibility to SCC environments.
- Maintenance crew training on threaded fasteners is performed.

In order for SCC to occur, three conditions must exist: a susceptible material, high tensile stresses, and a corrosive environment. At St. Lucie, the potential for SCC of fasteners is minimized by typically utilizing American Society of Testing and Materials (ASTM) A193, Grade B7 bolting material and limiting contaminants, such as chlorides and sulfur, in lubricants and sealant compounds. Additionally, sound maintenance bolt torquing practices are used to control bolting material stresses. The use of ASTM A193, Grade B7 bolting specifies a minimum yield strength of 105 Ksi, which is well below the 150 Ksi threshold value specified in EPRI NP-5769, "Degradation of Bolting in Nuclear Power Plants," April 1988. Bolting fabricated in accordance with this standard could be expected to have yield strengths less than 150 Ksi. However, since the maximum yield strength is not specified for this bolting material, absolute assurance cannot be provided that the yield strength of the bolting would not exceed 150 Ksi. For these cases, the combination of specifying ASTM A193 Grade B7 bolting material, control of bolt torquing, and control of contaminants will ensure that SCC will not occur. These actions have been effective in eliminating the potential for SCC of bolting materials. The results of a review of the St. Lucie condition report (1992 through 2000) and metallurgical report (1984 through 2000) databases support this conclusion in that no instances of bolting degradation due to SCC were identified. Additionally, review of NRC generic communications did not identify any recent bolting failures attributed to SCC. Therefore, loss of mechanical closure integrity due to SCC of low alloy bolting materials is not an aging effect requiring management at St. Lucie Units 1 and 2.

3.1.1.1.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Class 1 and non-Class 1 reactor coolant piping components includes the following:

- NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Bulletin 82-02, " Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"
- NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Information Notice 82-14, "TMI-1 Steam Generator/Reactor Coolant System Chemistry/Corrosion Problem"
- NRC Information Notice 82-30, "Loss of Thermal Sleeves in Reactor Coolant System Piping at Certain Westinghouse PWR Power Plants"
- NRC Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion"
- NRC Information Notice 88-01, "Safety Injection Pipe Failure"
- NRC Information Notice 88-80, "Unexpected Piping Movement Attributed to Thermal Stratification"
- NRC Information Notice 90-10, "Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600"
- NRC Information Notice 90-29, "Cracking of Cladding and Its Heat-Affected Zone in the Base Metal of a Reactor Vessel Head"

- NRC Information Notice 92-15, "Failure of Primary System Compression Fittings"
- NRC Information Notice 92-86, "Unexpected Restriction to Thermal Growth of Reactor Coolant Piping"
- NRC Information Notice 93-90, "Unisolatable Reactor Coolant System Leak Following Repeated Application of Leak Sealant"
- NRC Information Notice 94-55, "Problems with Copes-Vulcan Pressurizer Power-Operated Relief Valves"
- NRC Information Notice 97-19, "Safety Injection System Weld Flaw at Sequoyah Nuclear Power Plant, Unit 2"
- NRC Information Notice 97-46, "Unisolable Crack in High-Pressure Injection Piping"
- NRC Information Notice 98-45, "Cavitation Erosion of Letdown Line Orifices Resulting in Fatigue Cracking of Pipe Welds"
- NRC Information Notice 2000-17, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer"
- SOER 25-87, "Pressurizer Surge Line Thermal Stratification″

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.1.1.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Class 1 reactor coolant piping component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.1.1.2.

3.1.1.1.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.1.1.2. Table 3.1-1 contains the results of the aging management review for Class 1 reactor coolant piping components and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Thermal Aging Embrittlement of CASS Program

St. Lucie plant-specific programs:

- Alloy 600 Inspection Program
- Small Bore Class 1 Piping Inspection

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Class 1 reactor coolant piping components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.1.2 NON-CLASS 1 PIPING

Non-Class 1 reactor coolant piping components are within the scope of license renewal, as discussed in Subsection 2.3.1.1.2. Non-Class 1 reactor coolant piping components that are subject to an aging management review are listed in Table 3.1-1.

3.1.1.2.1 MATERIALS AND ENVIRONMENTS

Non-Class 1 reactor coolant piping components are exposed to internal environments of treated water - primary and external environments of containment air and potential borated water leaks (see Tables 3.0-1 and 3.0-2).

Non-Class 1 reactor coolant piping components are constructed of cast stainless steel, stainless steel, and carbon steel. The non-Class 1 reactor coolant piping components, their intended functions, the materials, and environments are listed in Table 3.1-1.

3.1.1.2.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of mechanical closure integrity

<u>CRACKING</u>

Cracking due to stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie Units 1 and 2, cracking due to fatigue is identified as a TLAA and is addressed in Subsection 4.3.2.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from non-Class 1 reactor coolant piping components. In addition, to reduce the susceptibility of non-Class 1 reactor coolant piping component materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Units 1 and 2. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the non-Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

REDUCTION IN FRACTURE TOUGHNESS

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 microstructure and properties of a material due to exposure to elevated temperatures for an extended period. The only non-Class 1 reactor coolant piping components subject to reduction in fracture toughness due to thermal embrittlement are austenitic stainless steel castings.

Screening of non-Class 1 cast austenitic stainless steel valves for susceptibility to thermal embrittlement is not required during the period of extended operation [Reference 3.1-2]. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that reduction in fracture toughness due to thermal aging is managed and that the intended function of the non-Class 1 cast austenitic stainless steel valves is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity is an aging effect requiring management for the period of extended operation. 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. Mechanical closure bolting associated with non-Class 1 reactor coolant piping components is made of carbon steel bolting material and is subject to aggressive chemical attack from potential borated water leaks. 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 function of non-Class 1 reactor coolant piping components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

As described in Subsection 3.1.1.1.2, loss of mechanical closure integrity due to SCC of low alloy bolting materials is not an aging effect requiring management at St. Lucie Units 1 and 2.

3.1.1.2.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to non-Class 1 reactor coolant piping components is included in the listing provided in Subsection 3.1.1.1.3.

No aging effects requiring management were identified from the documents listed in Subsection 3.1.1.1.3 beyond those already identified in Subsection 3.1.1.2.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of non-Class 1 reactor coolant piping component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.1.2.2.

3.1.1.2.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.1.2.2. Table 3.1-1 contains the results of the aging management review for non-Class 1 reactor coolant piping components and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program

St. Lucie plant-specific programs:

- None

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the non-Class 1 reactor coolant piping components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.2 PRESSURIZERS

The pressurizers are within the scope of license renewal, as discussed in Subsection 2.3.1.2. Pressurizer components that are subject to an aging management review are listed in Table 3.1-1.

The pressurizers scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Spray heads (IV C2.5.4) - 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.
- Thermal sleeves (IV C2.5.5) - 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. The thermal sleeves are not part of the pressure boundary, but do provide thermal shielding to minimize nozzle low cycle thermal fatigue. Fatigue is identified as a TLAA and is analytically addressed in Subsection 4.3.1.
- Support keys, skirt, and shear lugs (IV C2.5.11) - The St. Lucie Units 1 and 2 designs do not include support keys and shear lugs.
- Pressurizer relief tanks (IV C2.6) - 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.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.1.2.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.1.2.4 and are detailed in the appropriate subsections of Appendix B. Pressurizer component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.2.1 MATERIALS AND ENVIRONMENTS

The pressurizers are exposed to an internal environment of treated water - primary and external environments of containment air and potential borated water leaks (see Tables 3.0-1 and 3.0-2).

Pressurizer components are constructed of stainless steel, cast stainless steel, Alloy 600/690, low alloy steel, and carbon steel. The pressurizer components, their intended functions, the materials, and environments are listed in Table 3.1-1. For corresponding component/commodity groups included in the GALL Report, FPL identified nickel plated Alloy 600 utilized for Unit 1 heater sleeves as an additional material.

3.1.2.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of material
- Loss of mechanical closure integrity

3.1.2.2.1 CRACKING

Cracking due to flaw growth and stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is analytically addressed in Subsection 4.3.1.

Growth of original manufacturing flaws over time due to service loading can cause cracking. Detection and evaluation of flaws is important in maintaining the structural integrity of the pressurizer pressure boundary. ASME Section XI inservice examinations of components are intended to detect significant flaw growth and development. These examinations provide assurance that significant flaws do not exist, or a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired, if necessary. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that flaw growth is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from the pressurizers. In addition, to reduce the susceptibility of pressurizer materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Alloy 600 components are susceptible to cracking due to PWSCC even though the water chemistry is controlled within plant requirements. Chemistry control helps to minimize the contaminants that cause PWSCC, but it is not adequate by itself since industry/plant failures have occurred. The Alloy 600 Inspection Program, in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that PWSCC is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

In addition, the pressurizer lower head cladding material, Alloy 82/182, is susceptible to cracking due to PWSCC. Potential clad cracking could propagate from PWSCC and cyclic loading into the ferrite base metal and weld metal. However, as indicated in the GALL Report, because the weld metal between the surge nozzle and the vessel lower head is subjected to the maximum stress cycles, periodic monitoring of this area as part of the inservice inspection program provides a monitoring program for this aging mechanism. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program provide assurance that PWSCC of the pressurizer lower head cladding is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.2.2.2 REDUCTION IN FRACTURE TOUGHNESS

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 microstructure and properties of a material due to exposure to elevated temperatures for an extended period. The only pressurizer components subject to reduction in fracture toughness due to thermal embrittlement are austenitic stainless steel castings. The only cast austenitic stainless steel components in the pressurizers are the surge nozzle safe ends. The Thermal Aging Embrittlement of CASS Program provides assurance that reduction in fracture toughness due to thermal aging is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.2.2.3 LOSS OF MATERIAL

Loss of material due to aggressive chemical attack is an aging effect requiring management for external surfaces of carbon and low alloy steel pressurizer components exposed to borated water leaks. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of material due to aggressive chemical attack is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.2.2.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack.

Loss of mechanical closure integrity due to stress relaxation is a relevant aging effect that requires management. This aging effect can be managed by periodic inservice inspections and leakage testing. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that loss of mechanical closure integrity due to stress relaxation is managed and that the intended function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

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. Mechanical closure bolting associated with the pressurizers is made of low alloy steel bolting material and is subject to aggressive chemical attack from potential borated water leaks. 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 function of the pressurizers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

As described in Subsection 3.1.1.1.2, loss of mechanical closure integrity due to SCC of low alloy bolting materials is not an aging effect requiring management at St. Lucie Units 1 and 2.

3.1.2.3 OPERATING EXPERIENCE

3.1.2.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for pressurizer operating experience includes the following:

- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"
- NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations"
- NRC Information Notice 82-30, "Loss of Thermal Sleeves in Reactor Coolant System Piping at Certain Westinghouse PWR Power Plants"
- NRC Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion"
- NRC Information Notice 88-80, "Unexpected Piping Movement Attributed to Thermal Stratification"
- NRC Information Notice 90-10, "Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.2.2.

3.1.2.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of pressurizer component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.2.2.

3.1.2.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.2.2. Table 3.1-1 contains the results of the aging management review for the pressurizers and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Thermal Aging Embrittlement of CASS Program

St. Lucie plant-specific programs:

- Alloy 600 Inspection Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the pressurizer components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.3 REACTOR VESSELS

The reactor vessels are within the scope of license renewal, as discussed in Subsection 2.3.1.3. Reactor vessel components that are subject to an aging management review are listed in Table 3.1-1.

The reactor vessels scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Vessel flange leak detection lines (IV A2.1.4) - 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.
- Control rod drive head penetration flange bolting (IV A2.2.3) - The St. Lucie Units 1 and 2 designs do not include these components.
- Safety injection nozzles (IV A2.3.3) - The St. Lucie Units 1 and 2 designs do not include these components.
- Safety injection nozzles safe ends (IV A2.4.3) - The St. Lucie Units 1 and 2 designs do not include these components.
- Bottom head instrument tubes (IV A2.7.1) - The St. Lucie Units 1 and 2 designs do not include these components.
- Skirt supports (IV A2.8.1) - The St. Lucie Units 1 and 2 designs do not include these components.
- Cantilever/column supports (IV A2.8.2) - The St. Lucie Units 1 and 2 designs do not include these components.
- Neutron shield tanks (IV A2.8.3) - The St. Lucie Units 1 and 2 designs do not include these components.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.1.3.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.1.3.4 and are detailed in the appropriate subsections of Appendix B. Reactor vessel component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.3.1 MATERIALS AND ENVIRONMENTS

Reactor vessel components are exposed to an internal environment of treated water - primary and external environments of containment air and potential borated water leaks (see Tables 3.0-1 and 3.0-2).

Reactor vessel components are constructed of stainless steel, low alloy steel, and Alloy 600. Reactor vessel components, their intended functions, the materials, and environments are listed in Table 3.1-1. For corresponding component/commodity groups included in the GALL Report, FPL identified stainless steel utilized for vent pipes as an additional material.

3.1.3.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of material
- Loss of mechanical closure integrity

3.1.3.2.1 CRACKING

Cracking due to flaw growth and stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is analytically addressed in Subsection 4.3.1.

Growth of original manufacturing flaws over time due to service loading can cause cracking. Detection and evaluation of flaws is important in maintaining the structural integrity of the reactor vessel pressure boundary. ASME Section XI inservice examinations of components are intended to detect significant flaw growth and development. These examinations provide assurance that significant flaws do not exist, or a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired, if necessary. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that flaw growth is managed and that the intended function of the reactor vessels is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from the reactor vessels. In addition, to reduce the susceptibility of reactor vessel materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the reactor vessels is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

PWSCC of the control element drive mechanism and incore instrumentation nozzle tubes is a recognized industry issue. The Alloy 600 Inspection Program has been specifically designed to address PWSCC of these penetrations. The Alloy 600 Inspection Program has also been credited for managing PWSCC of the Alloy 600 vent pipes and Unit 2 control element drive mechanism motor housing lower end fittings. The Alloy 600 Inspection Program, in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that the intended function of the control element drive mechanism and incore instrumentation nozzle tubes, vent pipes, and Unit 2 control element drive mechanism motor housing lower end fittings is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

PWSCC of the core stabilizing lugs and core stop lugs is an aging mechanism requiring management. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provide assurance that the intended function of the core stabilizing lugs and core stop lugs is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation. For the period of extended operation, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require ASME Section XI VT-1 examinations of the core stabilizing lugs and core stop lugs.

SCC is an aging mechanism for reactor vessel closure studs and nuts. Visual, surface, and volumetric inspections performed as part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program have proven to be effective for managing the aging effects of SCC and provide assurance that the intended function of the reactor vessel closure studs and nuts is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.3.2.2 REDUCTION IN FRACTURE TOUGHNESS

Fracture toughness is defined as the capability of a material to resist sudden failure caused by crack propagation. Fracture toughness of reactor vessel materials is reduced primarily by irradiation in the beltline region of the reactor vessel. Reduction in fracture toughness of reactor vessel beltline materials is an aging effect that requires management in the license renewal period. Several TLAAs associated with reduction in fracture toughness are addressed in Section 4.2. These TLAAs include pressurized thermal shock, upper-shelf energy, and pressure-temperature limit curves for heatup and cooldown. The Reactor Vessel Integrity Program ensures that the time-dependent parameters used in the TLAA evaluations remain valid for the license renewal period.

3.1.3.2.3 LOSS OF MATERIAL

Loss of material is an aging effect requiring management for the period of extended operation. The aging mechanisms that can cause loss of material for reactor vessels are mechanical wear and aggressive chemical attack.

Loss of material due to wear is an aging effect requiring management for the reactor vessel flange, reactor vessel closure studs, nuts and washers, and the core stabilizing lugs. Examinations performed as part of the existing ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that the intended function of these reactor vessel components is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Loss of material due to aggressive chemical attack is an aging effect requiring management for external surfaces of low alloy steel reactor vessel components exposed to borated water leaks. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of material due to aggressive chemical attack is managed and that the intended function of the reactor vessels is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.3.2.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity can result from aggressive chemical attack.

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. Mechanical closure bolting associated with the reactor vessels is made of low alloy steel bolting material and is subject to aggressive chemical attack from potential borated water leaks. 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 function of the reactor vessels is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.3.3 OPERATING EXPERIENCE

3.1.3.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for reactor vessel operating experience includes the following:

- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessels Head Penetration Nozzles"
- NRC Generic Letter 80-46, "Generic Technical Activity A-12 Fracture Toughness"
- NRC Generic Letter 81-19, "Thermal Shock to Reactor Pressure Vessels"
- NRC Generic Letter 82-26, "NUREG-0744, Rev. 1 - Pressure Vessel Material Fracture Toughness"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operation"
- NRC Generic Letter 92-01, "Reactor Vessel Structural Integrity"
- NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in PWR Systems"

- NRC Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion"
- NRC Information Notice 90-10, "Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600"
- NRC Information Notice 96-32, "Implementation of 10 CFR 50.55a(g)(6)(ii)(A), 'Augmented Examination of Reactor Vessel'"
- NRC Information Notice 2000-17, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer"
- NRC Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.3.2.

3.1.3.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of reactor vessel component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.3.2.

3.1.3.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.3.2. Table 3.1-1 contains the results of the aging management review for reactor vessel components and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program

St. Lucie plant-specific programs:

- Alloy 600 Inspection Program
- Reactor Vessel Integrity Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the reactor vessel components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4 REACTOR VESSEL INTERNALS

The reactor vessel internals are within the scope of license renewal, as discussed in Subsection 2.3.1.4. Reactor vessel internals components that are subject to an aging management review are listed in Table 3.1-1.

The reactor vessel internals scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Core shroud assembly bolts (IV B3.4.2) - The St. Lucie Units 1 and 2 designs do not include these components.
- Core support column bolts (IV B3.5.5) - The St. Lucie Units 1 and 2 designs do not include these components.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.1.4.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.1.4.4 and are detailed in the appropriate subsections of Appendix B. Reactor vessel internals component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.4.1 MATERIALS AND ENVIRONMENTS

The reactor vessel internals are exposed to an environment of treated water - primary (see Table 3.0-1).

The reactor vessel internals components are constructed of stainless steel and cast stainless steel. The reactor vessel internals components, their intended functions, the materials, and environments are listed in Table 3.1-1.

3.1.4.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of material
- Loss of mechanical closure integrity
- Loss of preload

- Dimensional change

3.1.4.2.1 CRACKING

Cracking due to stress corrosion and irradiation assisted stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Subsection 4.3.1.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from reactor vessel internals components. In addition, to reduce the susceptibility of reactor vessel internals materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Premature failure by intergranular environmental cracking of materials exposed to ionizing radiation has been termed irradiation assisted stress corrosion cracking (IASCC). Experience in PWRs in the United States, France, and Belgium indicates that IASCC is a plausible aging mechanism for PWR reactor vessel internals components. As with SCC, IASCC requires stress, environment, and a susceptible material. However, in the case of IASCC, a normally nonsusceptible material is rendered susceptible by exposure to neutron irradiation. As discussed in the FPL response to NRC requests for additional information on the Turkey Point Units 3 and 4 license renewal application [Reference 3.1-3], susceptibility has been observed at fluences as low as 1×10^{21} n/cm^2 (E > 0.1 MeV) in laboratory studies on Type 304 stainless steel in PWR environments. Type 316 stainless steel is less susceptible and field information suggests that greater exposures are required for the development of susceptibility. Therefore, reactor vessel internals components exposed to fluences greater than $1x10^{21}$ n/cm^2 are potentially susceptible to IASCC and will be identified as part of the scope of the Reactor Vessel Internals Inspection Program. The Reactor Vessel Internals Inspection Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that IASCC is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.2.2 REDUCTION IN FRACTURE TOUGHNESS

Reduction in fracture toughness due to thermal embrittlement and irradiation embrittlement is an aging effect requiring management for the period of extended operation. Thermal embrittlement refers to gradual and progressive changes in the microstructure and properties of a material due to exposure to elevated temperatures for an extended period. Reactor vessel internals components made from cast austenitic stainless steel are potentially subject to reduction in fracture toughness due to thermal embrittlement. The cast austenitic stainless steel components in the reactor vessel internals are the flow bypass inserts (Unit 2 only), single tube control element assembly shrouds, and core support columns (Unit 1 only). The Reactor Vessel Internals Inspection Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that any reduction in fracture toughness due to thermal aging is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Reduction in fracture toughness due to irradiation embrittlement is an aging effect requiring management for the period of extended operation. Exposure to high-energy neutrons can cause changes in the properties of stainless steel used in reactor vessel internals. Neutron irradiation can produce changes in mechanical properties by increasing yield and ultimate strength, and correspondingly decreasing ductility and fracture toughness of reactor vessel internals component materials. As discussed in the FPL response to NRC requests for additional information on the Turkey Point Units 3 and 4 license renewal application, studies show that embrittlement of stainless steel can occur at fluences as low as $1x10^{21}$ n/cm^2 (E > 0.1 MeV).

For St. Lucie Units 1 and 2, the following reactor vessel internals components are located in the active fuel region and are exposed to high fluence, and thus are potentially susceptible to irradiation embrittlement:

- Core support barrels
- Core support barrel patches (Unit 1 only)
- Core support barrel expandable plugs (Unit 1 only)
- Core support barrel upper flanges
- Core support barrel alignment keys
- Core shroud assemblies
- Core support plates
- Fuel alignment pins
- Lower support structure beam assemblies
- Core support columns
- Cylinder and bottom plates
- Snubber spacer blocks

Confirmation of those reactor vessel internals components exposed to fluences greater than $1x10^{21}$ n/cm^2 (E > 0.1 MeV) will be performed as a part of the scope of the Reactor Vessel Internals Inspection Program.

Therefore, reduction in fracture toughness due to irradiation embrittlement is a potential aging effect requiring management for the reactor vessel internals components listed above. The Reactor Vessel Internals Inspection Program and the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that any reduction in fracture toughness due to irradiation embrittlement is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.2.3 LOSS OF MATERIAL

Loss of material due to mechanical wear is an aging effect requiring management for the period of extended operation. Loss of material due to wear can occur on the fuel alignment plate (Unit 2 only), fuel alignment plate guide lugs (Unit 1 only), fuel alignment plate guide lug inserts, holddown rings, control element assembly extension shaft guides, core support barrel upper flanges, core support barrel alignment keys, fuel alignment pins, and snubber spacer blocks. Inspections performed as part of the existing ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.2.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity of fuel alignment plate guide lug bolts (Unit 1 only), fuel alignment plate guide lug insert bolts, and control element assembly 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 Reactor Vessel Internals Inspection Program, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and the Chemistry Control Program provide assurance that loss of mechanical closure integrity is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.2.5 LOSS OF PRELOAD

Loss of preload due to stress relaxation of the reactor vessel internals holddown rings is an aging effect requiring management for the period of extended operation. Inspections performed as part of the existing ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide assurance that the loss of preload of the holddown springs is managed such that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.2.6 DIMENSIONAL CHANGE

Dimensional changes due to void swelling are a potential aging effect requiring management. Swelling, frequently referred to as cavity swelling or void swelling, is defined as a gradual increase in size (dimensions) of a given reactor vessel internals part due to irradiation conditions. Void swelling has been postulated from laboratory testing for liquid-metal fast breeder reactors (LMFBRs).

During the past 30 years, swelling of PWR internals components was not considered a significant age-related degradation mechanism. However, Garner, et al. [Reference 3.1-4], concluded that, based on LMFBR data, end-of-life exposures of some PWR internals will lead to significant levels ($\geq$ 10%) of swelling. Foster, et al. [Reference 3.1-5], concluded that at the approximate reactor internals end-of-life dose of 100 displacements per atom, swelling would be less than 2% at irradiation temperatures between 572°F and 752°F. To date, field service experience in PWR plants has not shown any evidence of swelling.

With respect to swelling, industry data are currently being evaluated as part of Westinghouse Owners Group and EPRI Material Reliability Project programs. At present there have been no indications from the different reactor vessel internals bolt removal programs, or from any of the other inspection and functional evaluations (e.g., refueling), that there are any discernible effects attributable to swelling. An industry initiative to consider the accumulated data, engineering evaluations of the ramifications of swelling, and the field observations is presently in progress.

In summary, it is known that void swelling can occur under certain conditions. The extent to which it degrades intended functions cannot be quantified but, at this point, some minor degradation in the form of dimensional changes is assumed. The Reactor Vessel Internals Inspection Program includes an evaluation of dimensional changes due to void swelling. If determined to be significant, program inspections will be performed. Therefore, the Reactor Vessel Internals Inspection Program provides assurance that the aging effect of dimensional change due to swelling is managed and that the intended function of the reactor vessel internals is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4.3 OPERATING EXPERIENCE

3.1.4.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for reactor vessel internals operating experience includes the following:

- NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors"
- NRC Information Notice 87-19, "Perforation and Cracking of Rod Control Cluster Assemblies"
- NRC Information Notice 87-44, "Thimble Tube Thinning in Westinghouse Reactors"
- NRC Information Notice 90-68, "Stress Corrosion Cracking of Reactor Coolant Pump Bolts (A286 IGSCC)"
- NRC Information Notice 93-79, "Core Shroud Cracking at Beltline Region Welds in Boiling-Water Reactors"
- NRC Information Notice 94-42, "Cracking in the Lower Region of the Core Shroud in Boiling Water Reactors"
- NRC Information Notice 98-11, "Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.4.2.

3.1.4.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of reactor vessel internals component aging, in addition to interviews with responsible engineering personnel. The St. Lucie Unit 1 reactor vessel internals thermal shield was removed, in 1983, as a result of flow-induced high-cycle fatigue. Damage to the core support barrel was repaired by the installation of patches and expandable plugs to maintain bypass leakage at an acceptable level and to assure continued core support barrel structural integrity [Reference 3.1-6]. TLAAs associated with the reactor vessel internals core support barrel repairs are addresses in Subsection 4.6.3. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.4.2.

3.1.4.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.4.2. Table 3.1-1 contains the results of the aging management review for the reactor vessel internals components and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Chemistry Control Program

St. Lucie plant-specific programs:

- Reactor Vessel Internals Inspection Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the reactor vessel internals components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.5 REACTOR COOLANT PUMPS

The reactor coolant pumps are within the scope of license renewal, as discussed in Subsection 2.3.1.5. Reactor coolant pump components that are subject to an aging management review are listed in Table 3.1-1.

The reactor coolant pumps scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. No component/commodity groups identified in the GALL Report were exempted from the plant specific aging management review for St. Lucie Units 1 and 2.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.1.5.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.1.5.4 and are detailed in the appropriate subsections of Appendix B. Reactor coolant pump component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.5.1 MATERIALS AND ENVIRONMENTS

Reactor coolant pumps are exposed to an internal environment of treated water - primary, and external environments of containment air and potential borated water leaks. The lower seal heat exchangers are exposed to internal environments of treated water- other and treated water - primary (see Tables 3.0-1 and 3.0-2).

The reactor coolant pump and lower seal heat exchanger components are constructed of stainless steel, cast stainless steel, and low alloy steel. The reactor coolant pump and lower seal heat exchanger components, their intended functions, the materials, and environments are listed in Table 3.1-1.

3.1.5.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking
- Reduction in fracture toughness
- Loss of material
- Loss of mechanical closure integrity

3.1.5.2.1 CRACKING

Cracking due to flaw growth and stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is analytically addressed in Subsection 4.3.1.

Growth of original manufacturing flaws over time due to service loading can cause cracking. Detection and evaluation of flaws is important in maintaining the structural integrity of the reactor coolant pump pressure boundary. ASME Section XI inservice examinations of components are intended to detect significant flaw growth and development. These examinations provide assurance that significant flaws do not exist, or a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired, if necessary. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that flaw growth is managed and that the intended function of the reactor coolant pumps is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from the reactor coolant pumps. In addition, to reduce the susceptibility of reactor coolant pump materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the reactor coolant pumps is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.5.2.2 REDUCTION IN FRACTURE TOUGHNESS

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 microstructure and properties of a material due to exposure to elevated temperatures for an extended period. The only reactor coolant pump components subject to reduction in fracture toughness due to thermal embrittlement are austenitic stainless steel castings. The reactor coolant pump casings and covers are fabricated from cast austenitic stainless steel.

The cast austenitic stainless steel reactor coolant pump casings and covers do not require an aging management program to manage thermal embrittlement beyond the examinations programmatically required by ASME Section XI as modified by Code Case N-481. Accordingly, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that any reduction in fracture toughness due to thermal aging is managed and that the intended function of the reactor coolant pumps is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.5.2.3 LOSS OF MATERIAL

Loss of material is an aging effect requiring management for the period of extended operation. The aging effects that can cause loss of material for the reactor coolant pump lower seal heat exchanger are microbiologically influenced corrosion and pitting corrosion.

Loss of material due to microbiologically influenced corrosion and pitting corrosion has been identified as an aging effect for the outside diameter of the reactor coolant pump lower seal heat exchanger tubing. The Chemistry Control Program provides assurance that the aging effect of loss of material due to microbiologically influenced corrosion and pitting corrosion is managed and that the intended function of the reactor coolant pump lower seal heat exchangers is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.5.2.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack.

Loss of mechanical closure integrity due to stress relaxation is a relevant aging effect that requires management. This aging effect can be managed by periodic inservice inspections and leakage testing. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that loss of mechanical closure integrity due to stress relaxation is managed and that the intended function of the reactor coolant pumps is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

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. Mechanical closure bolting associated with the reactor coolant pump components is made of low alloy steel bolting material and is subject to aggressive chemical attack. 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 function of the reactor coolant pumps is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

As described in Subsection 3.1.1.1.2, loss of mechanical closure integrity due to SCC of low alloy bolting materials is not an aging effect requiring management at St. Lucie.

3.1.5.3 OPERATING EXPERIENCE

3.1.5.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for reactor coolant pumps operating experience includes the following:

- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion"

- NRC Information Notice 93-61, "Excessive Reactor Coolant Leakage Following a Seal Failure in a Reactor Coolant Pump or Reactor Recirculation Pump"
- NRC Information Notice 93-84, "Determination of Westinghouse Reactor Coolant Pump Seal Failure"
- NRC Information Notice 97-31, "Failures of Reactor Coolant Pump Thermal Barriers and Check Valves at Foreign Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.5.2.

3.1.5.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of reactor coolant pump component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.5.2.

3.1.5.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.5.2. Table 3.1-1 contains the results of the aging management review for the reactor coolant pumps and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program

St. Lucie plant-specific programs:

- None

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the reactor coolant pump components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.6 STEAM GENERATORS

The steam generators are within the scope of license renewal, as discussed in Subsection 2.3.1.6. Steam generator components that are subject to an aging management review are listed in Table 3.1-1.

The steam generators scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.1-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Feedwater impingement plates and supports (IV D1.1.6) - The St. Lucie Units 1 and 2 designs do not include these components.
- Tube support plates (IV D1.2.4) - The St. Lucie Units 1 and 2 designs do not include these components.
- Feedwater inlet rings and supports (IV D1.3.1) - 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.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.1.6.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.1.6.4 and are detailed in the appropriate subsections of Appendix B. Steam generator component/commodity groups identified in Table 3.1-1 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.1.6.1 MATERIALS AND ENVIRONMENTS

The steam generators are exposed to internal environments of treated water - primary and treated water - secondary, and external environments of containment air and potential borated water leaks (see Tables 3.0-1 and 3.0-2).

The steam generator components are constructed of stainless steel, low alloy steel, carbon steel, Alloy 600, Alloy 600 HTMA (high temperature mill annealed), Alloy 690, and Alloy 690 TT (thermally treated). The steam generator components, their intended functions, the materials, and environments are listed in Table 3.1-1.

3.1.6.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Table 3.1-1 and are summarized in the following paragraphs.

The following internal and external aging effects require management during the period of extended operation:

- Cracking

- Loss of material
- Loss of mechanical closure integrity

3.1.6.2.1 CRACKING

Cracking due to flaw growth and stress corrosion is an aging effect requiring management for the period of extended operation. At St. Lucie, cracking due to fatigue is identified as a TLAA and is analytically addressed in Subsection 4.3.1. Based on industry experience with fatigue cracking of feedwater nozzles, additional discussion is provided below.

Growth of original manufacturing flaws over time due to service loading can cause cracking. Detection and evaluation of flaws is important in maintaining the structural integrity of the steam generator pressure boundary. ASME Section XI inservice examinations of components are intended to detect significant flaw growth and development. These examinations provide assurance that significant flaws do not exist, or a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired, if necessary. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that flaw growth is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

SCC is localized and caused by a combination of stress, susceptible material, and an aggressive environment. Specific design, fabrication, and construction measures were taken to minimize or eliminate susceptible material from steam generator components. In addition, to reduce the susceptibility of steam generator materials to SCC, FPL prevents sensitized stainless steels from coming in contact with an aggressive environment at St. Lucie Nuclear Plant. The Chemistry Control Program provides assurance that SCC is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Industry operating experience has shown steam generator 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 steam generator feedwater nozzle is required for the period of extended operation. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that cracking due to fatigue is managed and that the intended function of the steam generator feedwater nozzles is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Industry experience has shown that Alloy 600 steam generator tubing is susceptible to PWSCC and secondary side intergranular attack (IGA) and intergranular stress corrosion cracking (IGSCC). The aging effects of IGA/IGSCC and PWSCC can be managed by the continuation of the current steam generator tube inservice inspection program. The Chemistry Control Program and steam generator tube inspections performed in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Steam Generator Integrity Program provide assurance that IGA/IGSCC and PWSCC are managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Industry experience has also shown steam generator 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, only two cases of leaking tube plugs were recorded, both in the original Unit 1 steam generators, in 1996. However, since the industry has experienced PWSCC of steam generator tube plugs, PWSCC has been determined to be an aging effect requiring management. The Steam Generator Integrity Program and the Chemistry Control Program provide assurance that PWSCC is managed and that the intended function of the steam generator tube plugs is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Steam generator primary instrument nozzles, fabricated from Alloy 600, have not exhibited aging effects due to 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 reactor vessel upper head control element drive mechanism housing tubes. It appears that PWSCC of the Alloy 600 instrument nozzles is not likely to be significant during the period of extended operation. However, since Alloy 600 in general has susceptibility to PWSCC, primary instrument nozzle PWSCC has been determined to be an aging effect requiring management. The Alloy 600 Inspection Program, in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that PWSCC is managed and that the intended function of the primary instrument nozzles is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.6.2.2 LOSS OF MATERIAL

Loss of material is an aging effect requiring management for the period of extended operation. The aging mechanisms that can cause loss of material for the steam generators are general corrosion, crevice corrosion, pitting corrosion, flow accelerated corrosion, mechanical wear, and aggressive chemical attack.

General corrosion, pitting corrosion, and crevice corrosion have been identified as aging mechanisms for internal surfaces of carbon steel and low alloy steel components on the steam generator secondary side. General corrosion, pitting corrosion, and crevice corrosion of the secondary-side steam generator internal surfaces are mitigated by maintaining adequate secondary-side chemistry controls. The Chemistry Control Program provides assurance that general corrosion, pitting corrosion, and crevice corrosion are managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Pitting of the secondary side of the steam generator 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 steam generators due to 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 Chemistry Control Program and Steam Generator Integrity Program provide assurance that pitting corrosion is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Flow accelerated corrosion has been identified as a potential aging mechanism for feedwater, steam outlet, and blowdown nozzles and safe ends; 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 degradation of steam generator feedwater, steam outlet, or blowdown nozzles and safe ends, they are exposed to conditions conducive to flow accelerated corrosion. The Flow Accelerated Corrosion Program provides assurance that flow accelerated corrosion of the internal surfaces of the steam generator feedwater, steam outlet, and blowdown nozzles and safe ends is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation. The Steam Generator Integrity Program provides assurance that flow accelerated corrosion of the Unit 2 carbon steel tube support lattice bars is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Industry and St. Lucie plant experience have shown steam generator tube wear at contacts with tube support straps. Therefore, wear of the steam generator U-tubes is an aging mechanism that requires management. Eddy current examinations, performed in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Steam Generator Integrity Program provide assurance that tube wear is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

Loss of material due to aggressive chemical attack has been identified as an aging effect requiring management for external surfaces of carbon steel components exposed to borated water leaks. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of material due to aggressive chemical attack is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.6.2.3 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack.

Loss of mechanical closure integrity due to stress relaxation is a relevant aging effect that requires management. This aging effect can be managed by following the current periodic inservice inspection and leakage testing program. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that loss of mechanical closure integrity due to stress relaxation is managed and that the intended function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

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. Low alloy steel mechanical closure bolting associated with the steam generators and exposed to potential borated water leaks is subject to aggressive chemical attack. 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 function of the steam generators is maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

As described in Subsection 3.1.1.1.2, loss of mechanical closure integrity due to SCC of low alloy bolting materials is not an aging effect requiring management at St. Lucie Units 1 and 2.

3.1.6.3 OPERATING EXPERIENCE

3.1.6.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and NRC generic communications was performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for steam generator operating experience includes the following:

- NRC Bulletin 79-13, "Cracking in Feedwater System Piping"
- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 88-02, "Rapidly Propagating Cracks in Steam Generator Tubes"
- NRC Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs"
- NRC Generic Letter 82-32, "Potential Steam Generator Related Generic Requirements"
- NRC Generic Letter 85-02, "Staff Recommended Actions Stemming from NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes"
- NRC Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking"
- NRC Generic Letter 97-05, "Steam Generator Tube Inspection Techniques"
- NRC Generic Letter 97-06, "Degradation of Steam Generator Internals"
- NRC Information Notice 79-27, "Steam Generator Tube Ruptures at Two Plants"
- NRC Information Notice 82-06, "Failure of Steam Generator Primary Side Manway Closure Studs"
- NRC Information Notice 82-14, "TMI-1 Steam Generator/Reactor Coolant System Chemistry/Corrosion Problem"
- NRC Information Notice 82-37, "Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating Pressurized Water Reactor"

- NRC Information Notice 83-24, "Loose Parts in the Secondary Side of Steam Generators at Pressurized Water Reactors"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in Pressurized Water Reactor Systems"
- NRC Information Notice 84-49, "Intergranular Stress Corrosion Cracking Leading to Steam Generator Tube Failure"
- NRC Information Notice 85-37, "Chemical Cleaning of Steam Generators at Millstone 2"
- NRC Information Notice 85-65, "Crack Growth in Steam Generator Girth Welds"
- NRC Information Notice 88-06, "Foreign Objects in Steam Generators"
- NRC Information Notice 88-31, "Steam Generator Tube Rupture Analysis Deficiency"
- NRC Information Notice 88-99, "Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage"
- NRC Information Notice 89-33, "Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs"
- NRC Information Notice 89-65, "Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by Babcock and Wilcox"
- NRC Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Welds in Steam Generators"
- NRC Information Notice 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes"
- NRC Information Notice 91-43, "Recent Incidents Involving Rapid Increases in Primary-to-Secondary Leak Rate"
- NRC Information Notice 91-67, "Problems With the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing"
- NRC Information Notice 92-80, "Operation With Steam Generator Tubes Seriously Degraded"
- NRC Information Notice 93-20, "Thermal Fatigue Cracking of Feedwater Piping to Steam Generators"
- NRC Information Notice 93-52, Draft NUREG-1477, "Voltage-Based Interim Plugging Criteria for Steam Generator Tubes"
- NRC Information Notice 93-56, "Weaknesses in Emergency Operating Procedures Found as a Result of Steam Generator Tube Rupture"
- NRC Information Notice 94-05, "Potential Failure of Steam Generator Tubes Sleeved with Kinetically Welded Sleeves"
- NRC Information Notice 94-43, "Determination of Primary-to-Secondary Steam Generator Leak Rate"
- NRC Information Notice 94-62, "Operational Experience on Steam Generator Tube Leaks and Tube Ruptures"

- NRC Information Notice 94-88, "Inservice Inspection Deficiencies Result in Severely Degraded Steam Generator Tubes"
- NRC Information Notice 95-40, "Supplemental Information to Generic Letter 95-03, Circumferential Cracking of Steam Generator Tubes"
- NRC Information Notice 96-09, "Damage in Foreign Steam Generator Internals"
- NRC Information Notice 96-09, Supplement 1, "Damage in Foreign Steam Generator Internals"
- NRC Information Notice 96-38, "Results of Steam Generator Tube Examinations"
- NRC Information Notice 97-26, "Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes"
- NRC Information Notice 97-49, "B&W; Once-Through Steam Generator Tube Inspection Findings"
- NRC Information Notice 97-88, "Experience During Recent Steam Generator Inspections"
- NRC Information Notice 98-27, "Steam Generator Tube End Cracking"
- NRC Information Notice 2000-09, "Steam Generator Tube Failure at Indian Point Unit 2"
- NRC Information Notice 2001-16, "Recent Foreign and Domestic Experience with Degradation of Steam Generator Tubes and Internals"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.1.6.2.

3.1.6.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of steam generator component aging, in addition to interviews with responsible engineering personnel. The St. Lucie Unit 1 steam generators were replaced in 1997. This replacement was due to significant degradation of the original mill annealed Alloy 600 tubing. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.1.6.2.

3.1.6.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.1.6.2. Table 3.1-1 contains the results of the aging management review for the steam generators and summarizes the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program
- Steam Generator Integrity Program

St. Lucie plant-specific programs:

- Alloy 600 Inspection Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the steam generator components listed in Table 3.1-1 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.7 REFERENCES

3.1-1 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

3.1-2 Grimes, C. I. (NRC) letter to Walters, D. J. (NEI), "License Renewal Issue No. 98-0030, 'Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,'" May 19, 2000.

3.1-3 Hovey, R. J. (FPL) letter to U. S. Nuclear Regulatory Commission, "Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, Response to Request for Additional Information for the Review of the Turkey Point Units 3 and 4 License Renewal Application," L-2001-76, April 19, 2001.

3.1-4 Garner, F.A., Greenwood, L.R., and Harrod, D. L., "Potential High Fluence Response of Pressure Vessel Internals Constructed from Austenitic Stainless Steels," Sixth International Symposium on Environmental Degradation of Materials in Nuclear Power Systems, August 1993.

3.1-5 Foster, J. P. and Boltax, A., "Correlation of Irradiation Creep Data Obtained in Fast and Thermal Neutron Spectra with Displacement Cross Sections," Journal of Nuclear Materials, No. 89, 1980.

3.1-6 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1, Docket No. 50-335, Reactor Vessel Internals and Thermal Shield; Plant Recovery Program, Final Integrity and Stability of Internals - Conclusions and Findings," L-84-29, February 10, 1984.

TABLE 3.1-1
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Piping - Class 1 Components					
Internal Environment					
Valves [IV C2.4.1 and C2.4.2]	Pressure boundary	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Piping/fittings [IV C2.1.3] Safe ends [IV C2.2.7]	Pressure boundary	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Thermal Aging Embrittlement of CASS Program
Valves [IV C2.4.1 and C2.4.2] Piping/fittings ≥ 4 inches [IV C2.1.4, C2.2.1, and C2.2.3]	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Piping/fittings < 4 inches [IV C2.1.4, C2.1.5, C2.2.1, C2.2.3 - C2.2.6, and C2.2.8] Safe ends < 4 inches [IV C2.2.7]	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program Small Bore Class 1 Piping Inspection
Piping/fittings [IV C2.1.1 and C2.1.2] Nozzles	Pressure boundary	Carbon steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Piping - Class 1 Components (continued)					
Internal Environment (continued)					
Instrument nozzles Thermowells Fittings	Pressure boundary	Alloy 600/690	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Thermowells	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Restriction orifices	Pressure boundary Throttling	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Welds	Pressure boundary	ENiCrFe-3[1]	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

NOTES: 1 Used for joining dissimilar metals.

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Piping - Class 1 Components (continued)					
External Environment					
Valves Piping/fittings Safe ends Thermowells	Pressure boundary	Stainless steel	Containment air	None	None required
Valves Piping/fittings Safe ends	Pressure boundary	Stainless steel (cast)	Containment air	None	None required
Piping/fittings [IV C2.1.1 and C2.1.2] Nozzles	Pressure boundary	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Restriction orifices	Pressure boundary Throttling	Stainless steel	Containment air	None	None required
Instrument nozzles Thermowells Fittings	Pressure boundary	Alloy 600/690	Containment air	None	None required
Welds	Pressure boundary	ENiCrFe-3[1]	Containment air	None	None required
Bolting [IV C2.4.3]	Pressure boundary	Low alloy steel	Containment air	Loss of mechanical closure integrity	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

NOTES: 1 Used for joining dissimilar metals.

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Piping - Non-Class 1 Components					
Internal Environment					
Valves [IV C2.4.1 and C2.4.2] Piping/fittings [IV C2.2.5, C2.2.6, and C2.2.8] Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program
Valves [IV C2.4.1 and C2.4.2]	Pressure boundary	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program
				Reduction in fracture toughness	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Piping - Non-Class 1 Components (continued)					
External Environment					
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Containment air	None	None required
Valves	Pressure boundary	Stainless steel (cast)	Containment air	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Containment air	None	None required
Bolting [IV C2.4.3]	Pressure boundary	Stainless steel	Containment air	None	None required
Bolting [IV C2.4.3]	Pressure boundary	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Pressurizers					
Internal Environment					
Shells [IV C2.5.1] Upper heads [IV C2.5.1]	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Lower heads [IV C2.5.1]	Pressure boundary	Low alloy steel with Alloy 82/182 cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Spray nozzles [IV C2.5.2] Surge nozzles [IV C2.5.3] Relief valve nozzles Safety valve nozzles	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Instrument nozzles [IV C2.5.6] Heater sleeves [IV C2.5.10]	Pressure boundary	Alloy 600/690 Nickel plated Alloy 600 (Unit 1 heater sleeves)	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Surge nozzle safe ends	Pressure boundary	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Thermal Aging Embrittlement of CASS Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Pressurizers (continued)					
Internal Environment (continued)					
Spray nozzle safe ends [IV C2.5.7] Relief nozzle safe ends [IV C2.5.7] Instrument nozzle safe ends [IV C2.5.7] Safety valve flanges	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Manway covers [IV C2.5.8]	Pressure boundary	Carbon steel with stainless steel insert	Treated water - primary	Cracking	Chemistry Control Program
Heater sheaths [IV C2.5.10] Thermowells	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Pressurizers (continued)					
External Environment					
Shells [IV C2.5.1] Lower and upper heads [IV C2.5.1] Spray nozzles Surge nozzles Relief and safety valve nozzles	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Manway covers [IV C2.5.8]	Pressure boundary	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Instrument nozzles Heater sleeves	Pressure boundary	Alloy 600/690	Containment air	None	None required
Surge nozzle safe ends	Pressure boundary	Stainless steel (cast)	Containment air	None	None required
Support skirt integral attachments [IV C2.5.12]	Structural support	Carbon steel	Containment air	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Support skirt and flange	Structural support	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Pressurizers (continued)					
External Environment (continued)					
Spray nozzle safe ends Relief nozzle safe ends Instrument nozzle safe ends Safety valve flanges Heater sheaths Thermowells	Pressure boundary	Stainless steel	Containment air	None	None required
Manway cover bolting [IV C2.5.9]	Pressure boundary	Low alloy steel	Containment air	Loss of mechanical closure integrity	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels					
Internal Environment					
Closure head domes [IV A2.1.1]	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Closure head flanges	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element drive mechanism nozzle tubes (includes flanges for Unit 2) [IV A2.2.1]	Pressure boundary	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Unit 1 control element drive mechanism nozzle flanges [IV A2.2.1]	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element drive mechanism motor housings/upper pressure housings [IV A2.2.2]	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Unit 2 control element drive mechanism motor housing lower end fittings	Pressure boundary	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels (continued)					
Internal Environment (continued)					
Primary inlet nozzles [IV A2.3.1] Primary outlet nozzles [IV A2.3.2]	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Primary inlet nozzle safe ends Primary outlet nozzle safe ends	Pressure boundary	Carbon steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Upper shells	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Intermediate and lower shells [IV A2.5.2]	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Integrity Program
Vessel flanges [IV A2.5.3]	Pressure boundary Support reactor vessel internals	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Bottom heads [IV A2.5.4]	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels (continued)					
Internal Environment (continued)					
Core stabilizing lugs [IV A2.6]	Support reactor vessel internals	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Core stop lugs	Support reactor vessel internals	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Vent pipes [IV A2.7.2]	Pressure boundary	Alloy 600 Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Incore instrumentation nozzle tubes [IV A2.7.3]	Pressure boundary	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Incore instrumentation nozzle flange adaptors/ upper flanges/seal carrier assemblies	Pressure boundary	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program
Flow baffles	Flow distribution	Alloy 600	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels (continued)					
External Environment					
Closure head domes [IV A2.1.1]	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Closure head flanges [IV A2.1.2]	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Closure studs, nuts, and washers [IV A2.1.3]	Pressure boundary	Low alloy steel	Containment air	Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program
				Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element drive mechanism nozzle tubes (includes flanges for Unit 2)	Pressure boundary	Alloy 600	Containment air	None	None required
Unit 1 control element drive mechanism nozzle flanges	Pressure boundary	Stainless steel	Containment air	None	None required

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels (continued)					
External Environment (continued)					
Control element drive mechanism motor housings/upper pressure housings	Pressure boundary	Stainless steel	Containment air	None	None required
Unit 2 control element drive mechanism motor housing lower end fittings	Pressure boundary	Alloy 600	Containment air	None	None required
Primary inlet nozzles Primary outlet nozzles	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Primary inlet nozzle safe ends Primary outlet nozzle safe ends	Pressure boundary	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Nozzle support pads	Reactor vessel support	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Upper shells	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessels (continued)					
External Environment (continued)					
Intermediate and lower shells	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Vessel flanges [IV A2.5.3]	Pressure boundary	Low alloy steel	Containment air	Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bottom heads	Pressure boundary	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Vent pipes	Pressure boundary	Alloy 600 Stainless steel	Containment air	None	None required
Incore instrumentation nozzle tubes	Pressure boundary	Alloy 600	Containment air	None	None required
Incore instrumentation nozzle flange adapters/ upper flanges/seal carrier assemblies	Pressure boundary	Stainless steel	Containment air	None	None required
Refueling seal rings	Pressure boundary Structural support to refueling cavity	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management[1]	Program/Activity
Reactor Vessel Internals					
Upper guide structure support plate [IV B3.1.1]	Core support Flow distribution Guide/support instrumentation and control element assemblies	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Fuel alignment plate [IV B3.1.2]	Core support Flow distribution Guide/support instrumentation and control element assemblies	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material (Unit 2 only)	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Fuel alignment plate guide lugs [IV B3.1.3]	Core support	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material (Unit 1 only)	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

NOTES: 1. Void swelling, as appropriate, will be managed by the Reactor Vessel Internals Inspection Program (see Subsection 3.1.4.2.6).

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Fuel alignment plate guide lug inserts [IV B3.1.3]	Core support	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Holddown ring [IV B3.1.4]	Core support	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of preload Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element assembly extension shaft guides [IV B3.2.3]	Guide/support instrumentation and control element assemblies	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Flow bypass inserts (Unit 2 only)	Flow distribution	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element assembly instrument tubes Dual tube control element assembly shrouds (Unit 1 only) [IV B3.2.1] Control element assembly shroud base Incore instrumentation support plate Incore instrumentation guide tubes	Guide/support instrumentation and control element assemblies	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Single tube control element assembly shrouds [IV B3.2.1]	Guide/support instrumentation and control element assemblies	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Core support barrel [IV B3.3.1]	Core support Flow distribution Shield vessel	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Core support barrel patches (Unit 1 only) Core support barrel expandable plugs[1] (Unit 1 only) Core shroud assemblies [IV B3.4.1] Core support plate [IV B3.5.1] Cylinder and bottom plate	Core support Flow distribution	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Core support barrel upper flange [IV B3.3.2] Core support barrel alignment keys [IV B3.3.3] Fuel alignment pins [IV B3.5.2] Snubber spacer block [IV B3.5.6]	Core support	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

NOTES: 1 Loss of preload due to stress relaxation of the Unit 1 core support barrel expandable plugs was identified as a TLAA (Subsection 4.6.3). Option ii of 10 CFR 54.21(c)(1) was selected to address this aging effect.

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Lower support structure beam assemblies [IV B3.5.3] Unit 2 core support columns [IV B3.5.4]	Core support	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Unit 1 core support columns [IV B3.5.4]	Core support	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Control element assembly shroud bolts [IV B3.2.2]	Guide/support instrumentation and control element assemblies	Stainless steel	Treated water - primary	Loss of mechanical closure integrity	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Vessel Internals (continued)					
Fuel alignment plate guide lug bolts (Unit 1 only) Fuel alignment plate guide lug insert bolts Core shroud tie-rods (Unit 1 only) [IV B3.4.3] Snubber bolts (Unit 1 only)	Core support	Stainless steel	Treated water - primary	Loss of mechanical closure integrity	Chemistry Control Program Reactor Vessel Internals Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Pumps					
Internal Environment					
Reactor coolant pumps (casings and covers) [IV C2.3.1 and C2.3.2]	Pressure boundary	Stainless steel (cast)	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Reduction in fracture toughness	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Reactor coolant pumps (lower seal heat exchanger tubes)	Pressure boundary	Stainless steel	Treated water - primary (inside diameter)	Cracking	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material	Chemistry Control Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Coolant Pumps (continued)					
External Environment					
Reactor coolant pumps (casings and covers)	Pressure boundary	Stainless steel (cast)	Containment air	None	None required
Bolting [IV C2.3.3]	Pressure boundary	Low alloy steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program
			Containment air	Loss of mechanical closure integrity	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators					
Internal Environment					
Primary heads [IV D1.1.8] Stay cylinders	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Primary manway covers	Pressure boundary	Low alloy steel with Alloy 690/stainless steel diaphragm	Treated water - primary	Cracking	Chemistry Control Program
Primary inlet and outlet nozzles	Pressure boundary	Low alloy steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Primary inlet nozzle safe ends Primary outlet nozzle safe ends	Pressure boundary	Carbon steel with stainless steel cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Tubesheets	Pressure boundary	Low alloy steel with Alloy 600 cladding	Treated water - primary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
		Low alloy steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program
Primary instrument nozzles [IV D1.1.10]	Pressure boundary	Alloy 600/690	Treated water - primary	Cracking	Chemistry Control Program Alloy 600 Inspection Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators (continued)					
Internal Environment (continued)					
U-tubes [IV D1.2.1]	Pressure boundary Heat transfer	Alloy 690 TT (Unit 1) Alloy 600 HTMA (Unit 2)	Treated water - primary	Cracking	Chemistry Control Program Steam Generator Integrity Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Treated water - secondary	Loss of material	Chemistry Control Program Steam Generator Integrity Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Cracking	Chemistry Control Program Steam Generator Integrity Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Tube plugs [IV D1.2.3]	Pressure boundary	Alloy 690 TT	Treated water - primary	Cracking	Steam Generator Integrity Program Chemistry Control Program
Divider plates	Flow distribution	Stainless steel	Treated water - primary	Cracking	Chemistry Control Program
Upper and lower shells [IV D1.1.3] Transition cones [IV D1.1.4] Secondary heads [IV D1.1.1]	Pressure boundary	Low alloy steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators (continued)					
Internal Environment (continued)					
Feedwater nozzles and safe ends [IV D1.1.5] Steam outlet nozzle safe ends [IV D1.1.2] Unit 2 steam outlet nozzles [IV D1.1.2]	Pressure boundary	Low alloy steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Unit 1 steam outlet nozzles with integral flow orifices [IV D1.1.2]	Pressure boundary Throttling	Low alloy steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Blowdown nozzles	Pressure boundary	Low alloy steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Unit 1 secondary instrument nozzles	Pressure boundary	Alloy 690	Treated water - secondary	Cracking	Chemistry Control Program ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Unit 2 secondary instrument nozzles	Pressure boundary	Carbon steel	Treated water - secondary	Cracking	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
				Loss of material	Chemistry Control Program
Secondary manway and handhole closure covers	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators (continued)					
Internal Environment (continued)					
Tube bundle wrappers and wrapper supports	Structural support	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program
Unit 2 tube support lattice bars [IV D1.2.2]	Structural support	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Steam Generator Integrity Program
Unit 1 tube support lattice bars	Structural support	Stainless steel	Treated water - secondary	Cracking	Chemistry Control Program

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators (continued)					
External Environment					
Primary heads [IV D1.1.8] Primary inlet and outlet nozzles and safe ends Primary manway covers [IV D1.1.11]	Pressure boundary	Carbon steel Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Program
Conical skirts	Structural support	Low alloy steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Program
Upper and lower shells Secondary heads Transition cones Feedwater nozzles and safe ends Steam outlet nozzles and safe ends Blowdown nozzles Secondary closure covers	Pressure boundary	Low alloy steel	Containment air	None	None required
Upper vessel clevises and shear keys	Structural support	Low alloy steel	Containment air	None	None required
Primary instrument nozzles	Pressure boundary	Alloy 600/690	Containment air Borated water leaks	None	None required

TABLE 3.1-1 (continued)
REACTOR COOLANT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steam Generators (continued)					
External Environment (continued)					
Secondary instrument nozzles	Pressure boundary	Alloy 690 (Unit 1) Carbon steel (Unit 2)	Containment air	None	None required
Bolting (primary manways) [IV D1.1.11]	Pressure boundary	Low alloy steel	Containment air	Loss of mechanical closure integrity	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Program
Bolting (secondary manways and handholes) [IV D1.1.7]	Pressure boundary	Low alloy steel	Containment air	Loss of mechanical closure integrity	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

3.2 ENGINEERED SAFETY FEATURES SYSTEMS

The following systems are included in this section:

- Containment Cooling
- Containment Spray
- Containment Isolation
- Safety Injection (includes Shutdown Cooling)
- Containment Post Accident Monitoring

Subsection 2.3.2 provides a description of these systems and identifies the components requiring an aging management review for license renewal. For the Engineered Safety Features Systems, the specific materials and environments, the resulting aging effects, and the specific programs to manage these aging effects are listed in Tables 3.2-1 through 3.2-5. Appendix C contains the process that identified the aging effects requiring management for non-Class 1 components.

The aging management review results included under Containment Isolation 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 aging management review results described elsewhere in Sections 3.1, 3.2, 3.3, and 3.4. 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 aging management review results described in Section 3.5. The non-metallic and conductor portions of containment electrical penetrations are included in the electrical system aging management review results described in Section 3.6. Note, an aging management review was performed for all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described.

The Engineered Safety Features Systems scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.2-1]. The following component/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Containment Spray Heat Exchangers (V A.6) - The St. Lucie Units 1 and 2 design do not contain these components. The St. Lucie designs utilize the shutdown cooling heat exchangers to perform this function.
- Refueling Water Tank Circulation Pumps (V D1.3) - The St. Lucie Units 1 and 2 designs do not contain these components.
- Refueling Water Tank Heating Heat Exchangers (V D1.6) - The St. Lucie Units 1 and 2 designs do not contain these components.
- Primary Containment Heating and Ventilation System Filters (VII F3.4) - The St. Lucie Units 1 and 2 designs do not contain these components.

Additionally, the GALL Report does not address systems/subsystems included in Containment Post Accident Monitoring.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.2.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.2.4 and detailed in the appropriate subsections of Appendix B. Component/commodity groups identified in Tables 3.2-1 through 3.2-5 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.2.1 MATERIALS AND ENVIRONMENTS

The Engineered Safety Features Systems are exposed to internal environments of treated water - borated, treated water - other, raw water - drains, and air/gas; and external environments of outdoor, indoor - not air conditioned, containment air, and potential borated water leaks (see Tables 3.0-1 and 3.0-2). For corresponding component/commodity groups included in the GALL Report, FPL identified the following additional environments at St. Lucie Units 1 and 2:

- Internal environment of treated water - other for Containment Spray valves, thermowells, orifices, and piping and fittings
- Internal environment of raw water - valves, piping, and fittings associated with the reactor cavity sumps (included as part of Containment Spray)
- Internal environment of air/gas for Containment Isolation valves, piping, and fittings
- Internal environment of air/gas for refueling water tanks and safety injection tanks

The tanks, pumps, heat exchangers, piping, tubing, and associated components and commodity groups for these systems are constructed of stainless steel, nickel alloy, carbon steel, galvanized carbon steel, cast iron, aluminum, copper, brass, copper-nickel, glass, fiberglass reinforced vinyl ester, and rubber coated cloth. For corresponding component/commodity groups included in the GALL Report, FPL identified the following additional material applications at St. Lucie Units 1 and 2:

- Nickel alloy utilized for piping
- Aluminum and fiberglass reinforced vinyl ester utilized for the Unit 1 refueling water tank
- Brass utilized for valves
- Stainless steel utilized for spray nozzles, bolting, and safety injection tanks

The components and commodity groups, their intended functions, the materials, and environments for the Engineered Safety Features Systems are summarized in Tables 3.2-1 through 3.2-5.

For the Engineered Safety Features Systems, there are no systems or components considered inaccessible for inspection.

3.2.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Tables 3.2-1 through 3.2-5. The aging effects requiring management for each system are summarized in the following paragraphs.

Containment Cooling - The aging effects requiring management are loss of material for carbon steel, stainless steel, copper, copper-nickel, and galvanized carbon steel components; cracking for rubber coated cloth; and fouling for copper heat exchanger tubing and fins. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity.

Containment Spray - The aging effects requiring management are loss of material for carbon steel, stainless steel, brass, aluminum, and cast iron components; cracking for the fiberglass reinforced vinyl ester tank liner and certain stainless steel valves, thermowells, piping, tubing, and fittings; delamination of the fiberglass reinforced vinyl ester tank liner; and fouling for stainless steel heat exchanger tubing. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity.

Containment Isolation - The aging effect requiring management is loss of material for carbon steel. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity.

Safety Injection - The aging effects requiring management are loss of material for carbon steel, stainless steel, brass, and cast iron components; cracking for certain stainless steel components; and fouling for stainless steel heat exchanger tubing. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Note that fatigue of safety injection valves, piping, and fittings is identified in the GALL Report as an aging effect. At St. Lucie Units 1 and 2, fatigue is a TLAA and is addressed in Subsection 4.3.2.

Containment Post Accident Monitoring - The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity.

3.2.3 OPERATING EXPERIENCE

3.2.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Engineered Safety Features Systems includes the following:

- NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"
- NRC Bulletin 89-02, "Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design"
- NRC IE Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Piping Containing Boric Acid Solution at PWRs"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Information Notice 80-05, "Chloride Contamination of Safety Related Piping and Components"
- NRC Information Notice 81-38, "Potentially Significant Equipment Failures Resulting from Contamination of Air-Operated Systems"
- NRC Information Notice 82-09, "Cracking in Piping of Makeup Coolant Lines at B&W Plants"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in Pressurized Water Reactor Systems"
- NRC Information Notice 85-34, "Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping"
- NRC Information Notice 89-01, "Valve Body Erosion"
- NRC Information Notice 89-07, "Potentially Significant Equipment Failures Resulting from Contamination of Air-Operated Systems"

- NRC Information Notice 89-30, "High Temperature Environments at Nuclear Power Plants"
- NRC Information Notice 90-26, "Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety-Feature Systems"
- NRC Information Notice 90-39, "Recent Problems with Service Water Systems"
- NRC Information Notice 90-65, "Recent Orifice Plate Problems"
- NRC Information Notice 91-05, "Intergranular Stress Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles"
- NRC Information Notice 97-13, "Deficient Conditions Associated with Protective Coatings at Nuclear Power Plants"
- NRC Information Notice 99-01, "Deterioration of High-Efficiency Particulate Air Filters in a PWR Containment Fan Cooler Unit"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.2.2.

3.2.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Engineered Safety Features Systems component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.2.2.

3.2.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.2.2. Tables 3.2-1 through 3.2-5 contain the results of the aging management review for the Engineered Safety Features Systems and summarize the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program

St. Lucie plant-specific programs:

- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Engineered Safety Features Systems components listed in Tables 3.2-1 through 3.2-5 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.5 REFERENCES

3.2-1 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

TABLE 3.2-1
CONTAINMENT COOLING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment					
Containment fan cooler (HVS-1A, B, C, and D) housings [VII F3.1.2]	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler heat exchanger tubes	Pressure boundary Heat transfer	Copper	Treated water - other	Loss of material Fouling	Chemistry Control Program
Containment fan cooler heat exchanger headers and end caps	Pressure boundary	Copper	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Containment fan cooler heat exchanger vent plugs	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Unit 1 containment fan cooler heat exchanger stubs/flanges	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Unit 2 containment fan cooler heat exchanger stubs/flanges	Pressure boundary	Copper nickel	Treated water - other	Loss of material	Chemistry Control Program
Unit 2 containment fan cooler closed cooling water flanges	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Containment fan cooler motor heat exchanger tubes (Unit 1 only)	Pressure boundary Heat transfer	Copper	Treated water - other	Loss of material Fouling	Chemistry Control Program

TABLE 3.2-1 (continued)
CONTAINMENT COOLING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Containment fan cooler motor heat exchanger headers (Unit 1 only)	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Valves (Unit 1 only)	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings [VII F3.3.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Drip pans	Pressure boundary	Stainless steel	Raw water - drains	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Flexible connections [VII F3.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Thermowells	Pressure boundary	Stainless steel	Air/gas	None	None required

TABLE 3.2-1 (continued)
CONTAINMENT COOLING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment					
Containment fan cooler (HVS-1A, B, C, and D) housings [VII I.1.1]	Pressure boundary	Carbon steel	Containment air	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Containment fan cooler heat exchanger tubes	Pressure boundary Heat transfer	Copper	Containment air (wetted)	Loss of material Fouling	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler heat exchanger fins	Heat transfer	Copper	Containment air (wetted)	Loss of material Fouling	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler heat exchanger headers and end caps	Pressure boundary	Copper	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler heat exchanger vent plugs and frame side plates	Pressure boundary	Stainless steel	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Unit 1 containment fan cooler heat exchanger stubs/flanges [VII I.1.1]	Pressure boundary	Carbon steel	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Unit 2 containment fan cooler heat exchanger stubs/flanges	Pressure boundary	Copper nickel	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

TABLE 3.2-1 (continued)
CONTAINMENT COOLING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment (continued)					
Containment fan cooler motor heat exchanger tubes (Unit 1 only)	Pressure boundary Heat transfer	Copper	Containment air (wetted)	Loss of material Fouling	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler motor heat exchanger fins (Unit 1 only)	Heat transfer	Copper	Containment air (wetted)	Loss of material Fouling	Periodic Surveillance and Preventive Maintenance Program
Containment fan cooler motor heat exchanger headers (Unit 1 only) [VII I.1.1]	Pressure boundary	Carbon steel	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves (Unit 1 only) [VII I.1.1]	Pressure boundary	Carbon steel	Containment air	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Containment air (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Drip pans Thermowells	Pressure boundary	Stainless steel	Containment air	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Containment air	Cracking	Systems and Structures Monitoring Program

TABLE 3.2-1 (continued)
CONTAINMENT COOLING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment (continued)					
Ducts	Pressure boundary	Galvanized carbon steel	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-2
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment					
Unit 1 Refueling Water Tank	Pressure boundary	Aluminum	Treated water - borated	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
			Air/gas	None	None required
		Fiberglass reinforced vinyl ester	Treated water - borated	Cracking Delamination (including loss of adhesion)	ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
Unit 2 Refueling Water Tank [V D1.8.1-D1.8.3]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
			Air/gas	None	None required
NaOH Storage Tank (Unit 1 only)	Pressure boundary	Stainless steel	Treated water - other Air/gas	None[1]	None required
Hydrazine Storage Tank (Unit 2 only)	Pressure boundary	Stainless steel	Treated water - other Air/gas	None[1]	None required
NaOH Tank rupture disc (Unit 1 only)	Pressure boundary	Stainless steel	Air/gas	None	None required
Containment spray pumps [V A.3.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Hydrazine pumps (Unit 2 only)	Pressure boundary	Stainless steel	Treated water - other	None[1]	None required

NOTES: 1. Stainless steel in an environment of hydrazine or sodium hydroxide (NaOH) was determined to have no aging effects requiring management.

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Eductors (Unit 1 only) [V A.1.5]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Containment spray pump cooler tubes (Unit 1 only)	Pressure boundary Heat transfer	Stainless steel	Treated water - borated (inside diameter)	Loss of material Fouling	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program
Containment spray pump cooler shells (Unit 1 only)	Pressure boundary	Cast iron	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Containment spray pump cooler flex connectors (Unit 1 only)	Pressure boundary	Brass	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Refueling water tank vortex breaker (Unit 1 only)	Vortex prevention	Aluminum	Treated water - borated	Loss of material	Chemistry Control Program

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Valves [V A.4.1] Piping/fittings [V A.1.1] Tubing/fittings Thermowells [V A.1.3]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Treated water - other	None[2]	None required
Valves Piping/fittings (reactor cavity sump drains)	Pressure boundary	Stainless steel	Raw water - drains	None	None required
Piping	Pressure boundary	Nickel alloy	Raw water - drains Air/gas	None	None required

NOTES:
1. Portions of the system >140^{o}F are potentially susceptible to SCC (see Appendix C).
2. Stainless steel in an environment of hydrazine or NaOH was determined to have no aging effects requiring management.

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - other	None[1]	None required
Orifices [V A.1.2]	Pressure boundary Throttling	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Sight glass (Unit 1 only)	Pressure boundary	Carbon steel with stainless steel cladding	Treated water - other Air/gas	None[1]	None required
		Glass	Treated water - other Air/gas	None[1]	None required
Refueling water tank strainers	Filtration	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Spray nozzles	Pressure boundary Spray	Stainless steel	Air/gas	None	None required

NOTES: 1. Stainless steel and glass in a NaOH environment were determined to have no aging effects requiring management.

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment					
Unit 1 Refueling Water Tank	Pressure boundary	Aluminum	Outdoor	Loss of material[1]	Periodic Surveillance and Preventive Maintenance Program
Unit 2 Refueling Water Tank	Pressure boundary	Stainless steel	Outdoor	None	None required
NaOH Storage Tank (Unit 1 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Hydrazine Storage Tank (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Containment spray pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Eductors (Unit 1 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Hydrazine pumps (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Containment spray pump cooler shells (Unit 1 only)	Pressure boundary	Cast iron	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Containment spray pump cooler flex connectors (Unit 1 only)	Pressure boundary	Brass	Indoor - not air conditioned	None	None required

NOTES: 1. Plant experience has identified the potential for external loss of material due to galvanic corrosion of the tank bottom.

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment (continued)					
Valves Tubing/fittings Piping/fittings	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned Containment air	None	None required
Piping	Pressure boundary	Nickel alloy	Containment air Indoor - not air conditioned	None	None required
Thermowells	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned	None	None required
Rupture disc	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Piping/fittings	Pressure boundary	Stainless steel	Outdoor (ECCS pipe tunnel)	Loss of material[1] Cracking[1]	Periodic Surveillance and Preventive Maintenance Program
Sight glass (Unit 1 only) [V E1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Sight glass (Unit 1 only)	Pressure boundary	Glass	Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned	None	None required

NOTES: 1. 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.

TABLE 3.2-2 (continued)
CONTAINMENT SPRAY

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment (continued)					
Spray nozzles	Pressure boundary Spray	Stainless steel	Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air Outdoor	None	None required
Bolting (mechanical closures) [V A.1.4, A.3.2, A.4.2, A.5.2, D1.8.4]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air Outdoor	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Containment Purge					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
Debris screens (Unit 1 only)	Filtration	Stainless steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing/fittings	Pressure boundary	Stainless steel	Containment air	None	None required
Valves Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Debris screens (Unit 1 only)	Filtration	Stainless steel	Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3 (continued)
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Unit 1 Hydrogen Purge					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3 (continued)
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Unit 2 Continuous Containment/Hydrogen Purge					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Debris screen	Filtration	Carbon steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Debris screen [V E.1.1]	Filtration	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3 (continued)
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Integrated Leak Rate Test					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3 (continued)
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Service Air					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves	Pressure boundary	Brass	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves	Pressure boundary	Brass	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-3 (continued)
CONTAINMENT ISOLATION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Containment Vacuum Relief					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings [V E.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-4
SAFETY INJECTION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment					
Safety injection tanks [V D1.7.3]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
			Air/gas	None	None required
Low pressure safety injection pumps [V D1.2.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
High pressure safety injection pumps [V D1.2.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material[1]	Chemistry Control Program
Shutdown cooling heat exchanger tubes [V D1.5.2]	Pressure boundary Heat transfer	Stainless steel	Treated water - borated (inside diameter)	Loss of material Fouling Cracking	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program
Shutdown cooling heat exchanger tube sheets	Pressure boundary	Carbon steel clad with stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
			Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program

NOTES: 1. Cracking is not an applicable aging effect because the high pressure safety injection temperature is $\leq 140^{o}F$ (see Appendix C).

TABLE 3.2-4 (continued)
SAFETY INJECTION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Shutdown cooling heat exchanger channel nozzles, channel facings, channel cover facings [V D1.5.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
Shutdown cooling heat exchanger shells, baffles, tube supports [V D1.5.3]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Unit 1 low pressure safety injection pump cooler tubes [V D1.5.2]	Pressure boundary Heat transfer	Stainless steel	Treated water - borated (inside diameter)	Loss of material Fouling Cracking	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program
Unit 1 low pressure safety injection pump cooler shells [V D1.5.4]	Pressure boundary	Cast iron	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
High pressure safety injection pump cooler tubes [V D1.5.2]	Pressure boundary Heat transfer	Stainless steel	Treated water - borated (inside diameter)	Loss of material Fouling	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program

TABLE 3.2-4 (continued)
SAFETY INJECTION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Internal Environment (continued)					
Unit 1 high pressure safety injection pump cooler shells [V D1.5.4]	Pressure boundary	Cast iron	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Unit 2 high pressure safety injection pump cooler shells [V D1.5.3]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Unit 1 high pressure safety injection pump cooler tube shields	Pressure boundary	Brass	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Valves [V D1.4.1] Piping/fittings [V D1.1.1 - D1.1.5] Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
Orifices [V D1.2.3]	Pressure boundary Throttling	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program

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

TABLE 3.2-4 (continued)
SAFETY INJECTION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment					
Safety injection tanks	Pressure boundary	Stainless steel	Containment air	None	None required
High pressure safety injection pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Low pressure safety injection pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Shutdown cooling heat exchanger shells [V D1.5.3]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Shutdown cooling heat exchanger channel heads and channel covers	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Unit 1 low pressure safety injection pump cooler shells [V D1.5.4]	Pressure boundary	Cast iron	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Unit 1 high pressure safety injection pump cooler shells [V D1.5.4]	Pressure boundary	Cast iron	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Unit 2 high pressure safety injection pump cooler shells [V D1.5.3]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.2-4 (continued)
SAFETY INJECTION

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
External Environment (continued)					
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures) [V D1.1.7, D1.2.2, D1.4.2, and D1.5.5]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-5
CONTAINMENT POST ACCIDENT MONITORING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Containment Hydrogen Monitoring					
Internal Environment					
Flex hoses Valves Sample vessel (Unit 1) Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Containment air	None	None required
Flex hoses Valves Sample vessel (Unit 1 only) Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-5 (continued)
CONTAINMENT POST ACCIDENT MONITORING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Unit 2 Post Accident Sampling					
Internal Environment					
Valves	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Valves	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.2-5 (continued)
CONTAINMENT POST ACCIDENT MONITORING

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effect Requiring Management	Program/Activity
Containment Atmosphere Radiation Monitoring					
Internal Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

3.3 AUXILIARY SYSTEMS

The following systems are included in this section:

- Chemical and Volume Control
- 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 Supply
- Primary Makeup Water
- Sampling
- Service Water
- Turbine Cooling Water (Unit 1 only)
- Ventilation
- Waste Management

Subsection 2.3.3 provides a description of these systems and identifies the components requiring an aging management review for license renewal. For Auxiliary Systems, the specific materials and environments, the resulting aging effects, and the specific programs to manage these aging effects are listed in Tables 3.3-1 through 3.3-16. Appendix C contains the process that identified the aging effects requiring management for non-Class 1 components.

The Auxiliary Systems scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.3-1]. The following component/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- New Fuel Racks (VII A1.1) - 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.
- Spent Fuel Pool Cooling and Cleanup Filters (VII A3.2) - 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.

- Spent Fuel Pool Cooling and Cleanup Ion Exchangers (VII A3.5) - 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.
- Ultimate Heat Sink Pumps (VII C3.3) - The St. Lucie Units 1 and 2 designs do not include these components.
- Chemical and Volume Control Regenerative Heat Exchanger Bolting (VII E1.7.5) - The St. Lucie Units 1 and 2 designs do not include these components.
- Chemical and Volume Control Letdown Heat Exchanger Shells and Access Covers (VII E1.8.4) - 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.
- Chemical and Volume Control Basket Strainers (VII E1.9) - The St. Lucie Units 1 and 2 designs do not include these components.
- Control Room Area, Auxiliary and Radwaste Area Ventilation seals in access doors, dampers, and filters (VII F1.1.4, VII F1.4.2, VII F2.1.4, and VII F2.4.2) - These components are considered to be consumables and do not require an aging management review consistent with the guidance of NEI 95-10 [Reference 3.3-2].
- Primary Containment Heating and Ventilation System (VII F3) - Containment cooling is included in Section 3.2, Engineered Safety Features.
- Diesel Generator Building Ventilation (VII F4) - This system does not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore is not within the scope of license renewal.
- Diesel-Driven Fire Pumps and Fuel Supply Lines (VII G.8) - The St. Lucie Units 1 and 2 designs do not include these components.
- Diesel Engine Cooling Water Subsystem (VII H2.1.1 and H2.1.2) –Not applicable because the St. Lucie Units 1 and 2 designs utilize a self-contained cooling loop.

Additionally, the following component/commodity groups identified in the Auxiliary Systems section of the GALL Report are included in other sections of the St. Lucie Units 1 and 2 License Renewal Application, as indicated below:

- Spent Fuel Storage Racks (VII A2.1) - Section 3.5, Structures and Structural Components.
- Overhead Heavy Load and Light Load (Related to Refueling) Handling Cranes (VII B.1) - Section 3.5, Structures and Structural Components.
- Overhead Heavy Load and Light Load (Related to Refueling) Handling Rails (VII B.2) - Section 3.5, Structures and Structural Components.
- Primary Containment Heating and Ventilation (VII F3) - Section 3.2, Engineered Safety Features.

- Fire Protection fire barrier penetration seals, walls, ceilings, floors, and fire doors (VII G.1, VII G2, VII G3, VII G4, and VII G5) - Section 3.5, Structures and Structural Components.

For components/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.3.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.3.4 and detailed in the appropriate subsections of Appendix B. Component/commodity groups identified in Tables 3.3-1 through 3.3-16 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.3.1 MATERIALS AND ENVIRONMENT

The Auxiliary Systems are exposed to internal environments of air/gas, raw water - city water, raw water - salt water, raw water - drains, treated water - borated, treated water - other, lubricating oil, and fuel oil; and external environments of outdoor, indoor - not air conditioned, containment air, buried, embedded/encased, raw water - salt water, raw water - drains, and potential borated water leaks (see Tables 3.0-1 and 3.0-2). For corresponding component/commodity groups included in the GALL Report, FPL identified the following additional environments at St. Lucie Units 1 and 2:

- External environment of embedded/encased for Intake Cooling Water underground piping and fittings
- Internal environment of air/gas for Component Cooling Water tanks, valves, piping, and fittings
- Internal environment of treated water - other for Control Room Air Conditioning heat exchanger tubes
- Internal environment of air/gas for reactor coolant pump oil collection tanks, valves, piping, and fittings
- Internal environment of air/gas for diesel generator fuel oil and day tanks

The tanks, pumps, heat exchangers, housings, piping, tubing, valves, and associated components and commodity groups for these systems are constructed of carbon steel, galvanized carbon steel, stainless steel, nickel alloy, cast iron, aluminum, aluminum alloy, aluminum brass, aluminum bronze, brass, bronze, copper, copper alloy, copper nickel, fiberglass, glass, Monel, plastic, Plexiglas, polyester/rubber, rubber, rubber coated cloth, and titanium. For corresponding component/commodity groups included in the GALL Report, FPL identified the following additional material applications at St. Lucie Units 1 and 2:

- Nickel alloy utilized for piping
- Aluminum bronze utilized for pump casings
- Brass, copper alloy, aluminum, and plastic utilized for valves
- Galvanized carbon steel utilized for vessels, piping/fittings, and ducts
- Titanium and Monel utilized for orifices
- Rubber coated cloth utilized for flexible connections
- Stainless steel utilized for bolting
- Aluminum brass and fiberglass utilized for piping/fittings

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 aging management review process; see Table 3.0-2, "External Service Environments." Potential aging effects associated with these environments are reviewed and those aging effects requiring management are identified along with the credited aging management program(s). All other parts of systems and components can be accessed, if required. The Auxiliary Systems containing inaccessible parts are:

- Fire Protection that contains buried cast iron valves, hydrants, and piping/fittings, and embedded/encased cast iron piping/fittings
- Emergency Cooling Canal that contains embedded/encased carbon steel piping
- Intake Cooling Water that contains buried and embedded/encased carbon steel piping/fittings, and buried stainless steel piping/fittings and carbon steel bolting
- Primary Water that contains embedded/encased stainless steel piping/fittings
- Waste Management that contains embedded/encased stainless steel strainers and piping/fittings

The components, their intended functions, materials, and environments for the Auxiliary Systems are summarized in Tables 3.3-1 through 3.3-16.

3.3.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Tables 3.3-1 through 3.3-16. The aging effects requiring management for each system are summarized in the following paragraphs.

Chemical and Volume Control - The aging effects requiring management are loss of material and cracking for stainless steel components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity. Note that fatigue of regenerative heat exchangers, letdown heat exchangers, valves, piping, and fittings is identified in the GALL Report as an aging effect. At St. Lucie Units 1 and 2, fatigue is a TLAA and is addressed in Subsection 4.3.2.

Component Cooling Water - The aging effects requiring management 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.

Demineralized Makeup Water (Unit 2 only) - The aging effect requiring management is loss of material for stainless steel components.

Diesel Generators and Support Systems - The aging effects requiring management are loss of material for cast iron, carbon steel, stainless steel, and copper alloy components; cracking for rubber, polyester/rubber, and Plexiglas components; and loss of material and fouling for aluminum, brass, and copper radiator tubes and fins.

Emergency Cooling Canal - The aging effect requiring management is loss of material for carbon steel and aluminum bronze components.

Fire Protection - The aging effect requiring management is loss of material for carbon steel, stainless steel, cast iron, and copper alloy components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Fuel Pool Cooling - The aging effects requiring management are loss of material for carbon steel and stainless steel components; and loss of material and fouling (Unit 2 only) for stainless steel heat exchanger tubes. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Instrument Air - The aging effects requiring management are loss of material for galvanized carbon steel, carbon steel, brass, bronze, stainless steel, and copper alloy components; cracking for rubber and plastic components; and fouling for copper heat exchanger tubes. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Intake Cooling Water - The aging effects requiring management 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 effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Miscellaneous Bulk Gas Supply - The aging effect requiring management is loss of material for carbon steel components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Primary Makeup Water - The aging effects requiring management are loss of material for carbon steel, nickel alloy, and copper alloy components; loss of material and cracking for stainless steel components; and cracking for rubber components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Sampling - The aging effects requiring management are loss of material and cracking for stainless steel components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Service Water - The aging effects requiring management are loss of material for galvanized carbon steel and copper alloy components; and loss of material and cracking for stainless steel components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Turbine Cooling Water (Unit 1 only) - The aging effects requiring management are loss of material for carbon steel and stainless steel components; and loss of material and fouling for brass fan cooler tubes and fins.

Ventilation - The aging effects requiring management are loss of material for galvanized carbon steel, carbon steel, stainless steel, and copper nickel components; cracking for rubber coated cloth expansion joints; and fouling for copper nickel heat exchanger tubes. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

Waste Management - The aging effect requiring management is loss of material for carbon steel components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

3.3.3 OPERATING EXPERIENCE

3.3.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Auxiliary Systems includes the following:

- NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants"
- NRC Bulletin 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (asiatic clam) and Mytilus sp. (mussel)"
- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 88-08 and Supplements 1, 2, and 3, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"
- NRC Bulletin 89-02, "Stress Corrosion Cracking of High Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design"
- NRC Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Piping Containing Boric Acid Solution at PWRs"
- NRC Circular 80-11, "Emergency Diesel Generator Lube Oil Cooler Failures"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning"
- NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 79-19, "Pipe Cracks in Borated Water Systems at PWR Plants"
- NRC Information Notice 79-23, "Emergency Diesel Generator Lube Oil Coolers"
- NRC Information Notice 80-05, "Chloride Contamination of Safety-Related Piping and Components"
- NRC Information Notice 81-38, "Potentially Significant Equipment Failures Resulting from Contamination of Air-Operated Systems"
- NRC Information Notice 84-18, "Stress Corrosion Cracking in Pressurized Water Reactor Systems"
- NRC Information Notice 84-71, "Graphitic Corrosion of Cast Iron in Salt Water"

- NRC Information Notice 85-24, "Failures of Protective Coatings in Pipes and Heat Exchangers"
- NRC Information Notice 85-30, "Microbiologically Induced Corrosion of Containment Service Water System"
- NRC Information Notice 85-34, "Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping"
- NRC Information Notice 85-56, "Inadequate Environment Control for Components and Systems in Extended Storage or Lay-up"
- NRC Information Notice 86-96, "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water System"
- NRC Information Notice 88-17, "Summary of Responses to NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Information Notice 88-37, "Flow Blockage of Cooling Water to Safety System Components"
- NRC Information Notice 89-01, "Valve Body Erosion"
- NRC Information Notice 89-07, "Failures of Small Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Render Emergency Diesel Generators Inoperable"
- NRC Information Notice 90-26, "Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety Feature Systems"
- NRC Information Notice 90-39, "Recent Problems with Service Water Systems"
- NRC Information Notice 90-65, "Recent Orifice Plate Problems"
- NRC Information Notice 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems"
- NRC Information Notice 91-85, "Potential Failures of Thermostatic Control Valves for Diesel Generator Jacket Cooling Water System"
- NRC Information Notice 94-03, "Deficiencies Identified During Service Water System Operational Performance Inspections"
- NRC Information Notice 94-58, "Reactor Coolant Pump Lube Oil Fire"
- NRC Information Notice 94-59, "Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion"
- NRC Information Notice 94-79, "Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping"
- NRC Information Notice 96-67, "Vulnerability of Emergency Diesel Generators to Fuel Oil/Lubricating Oil Incompatibility"
- NRC Information Notice 97-13, "Deficient Conditions Associated with Protective Coatings at Nuclear Power Plants"
- NRC Information Notice 98-43, "Leaks in the Emergency Diesel Generator Lubricating Oil and Jacket Cooling Water Piping"

- NRC Information Notice 99-01, "Deterioration of High-Efficiency Particulate Air Filters in a PWR Containment Fan Cooler Unit"
- NRC Information Notice 99-07, "Failed Fire Protection Deluge Valves and Potential Testing Deficiencies in Preaction Sprinkler Systems"

No aging effects requiring management were identified from the above documents beyond those identified in Subsection 3.3.2.

3.3.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. The review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Auxiliary Systems component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.3.2.

3.3.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.3.2. Tables 3.3-1 through 3.3-16 contain the results of the aging management review for the Auxiliary Systems and summarize the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program (Water Chemistry Control and Closed-Cycle Closed Cooling Water Chemistry Subprograms)
- Fire Protection Program

St. Lucie plant-specific programs:

- Chemistry Control Program (Fuel Oil Chemistry Subprogram)
- Galvanic Corrosion Susceptibility Inspection Program
- Intake Cooling Water Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Pipe Wall Thinning Inspection Program
- Systems and Structures Monitoring Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Auxiliary Systems components listed in Tables 3.3-1 through 3.3-16 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.3.5 REFERENCES

3.3-1 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

3.3-2 NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, Nuclear Energy Institute, March 2001.

TABLE 3.3-1
CHEMICAL AND VOLUME CONTROL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Boric acid makeup tanks	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Volume control tanks	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
			Air/gas	None	None required
Boric acid makeup pumps	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Charging pumps [VII E1.5.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
				Cracking[1]	Periodic Surveillance and Preventive Maintenance Program
Letdown heat exchanger tubes[2] [VII E1.8.3]	Pressure boundary	Stainless steel	Treated water - borated (inside diameter)	Loss of material Cracking	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material	Chemistry Control Program
Letdown heat exchanger tubesheets [VII E1.8.2]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
			Treated water - other	Loss of material	Chemistry Control Program

NOTES: 1. Plant experience has identified the potential for Unit 2 charging pump cracking due to fatigue.
2. Heat transfer is not a license renewal intended function for the letdown heat exchangers.

TABLE 3.3-1 (continued)
CHEMICAL AND VOLUME CONTROL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Letdown heat exchanger channel heads and covers [VII E1.8.1]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
Regenerative heat exchangers (including tubes)[1] [VII E1.7.1 - E1.7.4]	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking	Chemistry Control Program
Valves [VII E1.3.1] Piping/fittings [VII E1.1.1] Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[2]	Chemistry Control Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
Housings (charging pump strainers, suction stabilizers, pulsation dampers, purification filters, letdown strainers, boric acid suction strainers, and ion exchangers)	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[2]	Chemistry Control Program

NOTES:
1. Heat transfer is not a license renewal intended function for the regenerative heat exchangers.
2. Portions of the system >140^{o}F are potentially susceptible to SCC (see Appendix C).

TABLE 3.3-1 (continued)
CHEMICAL AND VOLUME CONTROL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Strainer elements	Filtration	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program

NOTES: 1. Portions of the system >140^{o}F are potentially susceptible to SCC (see Appendix C).

TABLE 3.3-1 (continued)
CHEMICAL AND VOLUME CONTROL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Boric acid makeup tanks	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Volume control tanks	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Boric acid makeup pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Charging pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Letdown heat exchanger channel heads	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Regenerative heat exchanger	Pressure boundary	Stainless steel	Containment air	None	None required
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Piping/fittings (from boric acid makeup tanks to boric acid makeup pumps and charging pumps)	Pressure boundary	Stainless steel	Indoor - not air conditioned	Cracking[1]	Systems and Structures Monitoring Program

NOTES: 1. Plant experience has identified the potential for cracking of previously heat-traced piping and fittings.

TABLE 3.3-1 (continued)
CHEMICAL AND VOLUME CONTROL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Piping/fittings (refueling water tanks to charging pump suctions)	Pressure boundary	Stainless steel	Outdoor (ECCS pipe tunnel)	Loss of material[1] Cracking[1]	Periodic Surveillance and Preventive Maintenance Program
			Outdoor Indoor - not air conditioned	None	None required
Housings (purification filters, letdown strainers, boric acid suction strainers, ion exchangers, charging pump strainers, suction stabilizers, and pulsation dampers)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures) [VII E1.1.2, E1.2.1, E1.3.2, E1.4.1, E1.5.2, E1.6.1, E1.8.5, E1.10.1]	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel Stainless steel	Outdoor Indoor - not air conditioned Containment air	None	None required

NOTES: 1. Plant experience has identified the potential for SCC and loss of material due to pitting corrosion on stainless steel components located in the ECCS pipe tunnel.

TABLE 3.3-2
COMPONENT COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Component cooling water surge tanks [VII C2.4.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Component cooling water pumps [VII C2.3.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Component cooling water heat exchanger tubes [VII C1.3.5]	Pressure boundary Heat transfer	Aluminum brass	Raw water - salt water (inside diameter)	Loss of material Fouling	Intake Cooling Water Inspection Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program
Component cooling water heat exchanger tubesheets [VII C1.3.4]	Pressure boundary	Aluminum bronze	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
			Treated water - other	Loss of material	Chemistry Control Program
Component cooling water heat exchanger channels and doors [VII C1.3.2, C1.3.3]	Pressure boundary	Carbon steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Component cooling water heat exchanger shells and baffles [VII C1.3.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program

TABLE 3.3-2 (continued)
COMPONENT COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves [VII C2.2.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Valves [VII C2.2.1] Thermowells Tubing/Fittings Sight glasses (Unit 2 only)	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Valves (Unit 1 only)	Pressure boundary	Cast iron	Treated water - other	Loss of material	Chemistry Control Program
Valves Piping/fittings Sight glasses (Unit 1 only)	Pressure boundary	Carbon steel	Air/gas	None	None required
Piping/fittings [VII C2.1.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Pipe Wall Thinning Inspection Program[1] Galvanic Corrosion Susceptibility Inspection Program
Sight glasses (Unit 1 only)	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Sight glasses (Unit 2 only)	Pressure boundary	Stainless steel	Air/gas	None	None required

NOTES: 1. Plant experience has identified the potential for loss of material due to erosion of the carbon steel pipe downstream of throttle valves due to localized cavitation.

TABLE 3.3-2 (continued)
COMPONENT COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Sight glasses	Pressure boundary	Glass	Treated water - other	None	None required

TABLE 3.3-2 (continued)
COMPONENT COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Component cooling water surge tanks [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Component cooling water pumps [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Component cooling water heat exchanger shells, includes channels and doors [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned Containment air	None	None required
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
			Containment air	Loss of material	Systems and Structures Monitoring Program Galvanic Corrosion Susceptibility Inspection Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.3-2 (continued)
COMPONENT COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Valves (Unit 1 only)	Pressure boundary	Cast iron	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Outdoor Indoor - not air conditioned	None	None required
Sight glasses (Unit 1 only) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Sight glasses (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Sight glasses	Pressure boundary	Glass	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-3
DEMINERALIZED MAKEUP WATER (UNIT 2 ONLY)

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
External Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-4
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cooling Water System					
Internal Environment					
Cooling water expansion tanks	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Cooling water pumps	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Cooling water radiator headers	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Cooling water radiator tubes	Pressure boundary Heat transfer	Brass	Treated water - other	Loss of material Fouling	Chemistry Control Program
Valves Expansion joints	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Valves	Pressure boundary	Brass	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Piping/fittings [VII H2.1.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cooling Water System (continued)					
Internal Environment (continued)					
Tubing/fittings	Pressure boundary	Copper	Treated water - other	Loss of material	Chemistry Control Program
Tubing/fittings Thermowells Flexible hoses	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Flexible hoses	Pressure boundary	Rubber	Treated water - other	Cracking	Periodic Surveillance and Preventive Maintenance Program
Sight glasses	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
		Plexiglas	Treated water - other Air/gas	Cracking	Systems and Structures Monitoring Program

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cooling Water System (continued)					
External Environment					
Cooling water expansion tanks [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Cooling water pumps [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Cooling water radiator headers [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Cooling water radiator tubes	Pressure boundary Heat transfer	Brass	Indoor - not air conditioned	None	None required
Cooling water radiator fins (Unit 1 only)	Heat transfer	Copper	Indoor - not air conditioned	Loss of material[1] Fouling[1]	Periodic Surveillance and Preventive Maintenance Program
Cooling water radiator fins (Unit 2 only)	Heat transfer	Aluminum	Indoor - not air conditioned	Loss of material[1] Fouling[1]	Periodic Surveillance and Preventive Maintenance Program
Valves Piping/fittings Expansion joints [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves	Pressure boundary	Brass	Indoor - not air conditioned	None	None required
Tubing/fittings	Pressure boundary	Copper Stainless steel	Indoor - not air conditioned	None	None required

NOTES: 1. Plant experience shows a history of loss of material and fouling due to corrosion on fins.

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cooling Water System (continued)					
External Environment (continued)					
Flexible hoses	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
		Rubber	Indoor - not air conditioned	Cracking	Periodic Surveillance and Preventive Maintenance Program
Sight glasses [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Sight glasses	Pressure boundary	Plexiglas	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Air Start and Intake System					
Internal Environment					
Start-up air tanks (Unit 1 only)	Pressure boundary	Carbon steel	Air/gas	None	None required
Start-up air tanks (Unit 2 only)	Pressure boundary	Stainless steel	Air/gas	None	None required
Air start motors	Pressure boundary	Aluminum alloy	Air/gas	None	None required
Air start motor lubricators	Pressure boundary	Aluminum alloy	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings Flexible hoses	Pressure boundary	Stainless steel	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Tubing/fittings	Pressure boundary	Copper alloy	Air/gas	None	None required
Start-up air strainer housings (Unit 1 only)	Pressure boundary	Carbon steel	Air/gas	None	None required
Start-up air strainer housings (Unit 2 only)	Pressure boundary	Stainless steel	Air/gas	None	None required
Strainer elements	Filtration	Stainless steel	Air/gas	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Air Start and Intake System (continued)					
Internal Environment (continued)					
Intake air filter housings [VII H2.3.1 - H2.3.2]	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Flexible hoses	Pressure boundary	Polyester/rubber Rubber	Air/gas	Cracking	Periodic Surveillance and Preventive Maintenance Program

Notes: 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Air Start and Intake System (continued)					
External Environment					
Start-up air tanks (Unit 1 only) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Start-up air tanks (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Air start motors	Pressure boundary	Aluminum alloy	Indoor - not air conditioned	None	None required
Air start motor lubricators	Pressure boundary	Aluminum alloy	Indoor - not air conditioned	None	None required
Valves Piping/fittings Tubing/fittings Flexible hoses	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Valves Piping/fittings Tubing/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Tubing/fittings	Pressure boundary	Copper alloy	Indoor - not air conditioned	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Air Start and Intake System (continued)					
External Environment (continued)					
Start-up air strainer housings (Unit 1 only) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Start-up air strainer housings (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Intake air filter housings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Flexible hoses	Pressure boundary	Polyester/rubber Rubber	Indoor - not air conditioned	Cracking	Periodic Surveillance and Preventive Maintenance Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel Stainless steel	Indoor - not air conditioned	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Exhaust System					
Internal Environment					
Exhaust silencer [VII H2.4.2]	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings [VII H2.4.1]	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Expansion joints	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Exhaust silencer [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Expansion joints	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

Notes: 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Oil System					
Internal Environment					
Diesel fuel oil storage tanks [VII H1.4.1]	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Chemistry Control Program Periodic Surveillance and Preventive Maintenance Program
Diesel fuel oil storage tanks	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Diesel fuel oil day tanks [VII H2.5.1]	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Chemistry Control Program Periodic Surveillance and Preventive Maintenance Program
Diesel fuel oil day tanks	Pressure boundary	Carbon steel	Air/gas	None	None required
Diesel fuel oil transfer pumps	Pressure boundary	Stainless steel	Fuel oil	Loss of material	Chemistry Control Program
Diesel fuel oil pumps (Priming, engine-driven, etc.)	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Chemistry Control Program
Valves Piping/fittings	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Chemistry Control Program
			Air/gas	None	None required

NOTES: 1. Loss of material was identified as a potential aging mechanism due to the potential for moisture contamination.

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Oil System (continued)					
Internal Environment (continued)					
Valves	Pressure boundary	Bronze	Fuel oil	Loss of material	Chemistry Control Program
Tubing/fittings	Pressure boundary	Copper	Fuel oil	Loss of material	Chemistry Control Program
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Fuel oil	Loss of material	Chemistry Control Program
Tubing/fittings Filter housings	Pressure boundary	Carbon steel	Fuel oil	Loss of material	Chemistry Control Program
Orifices	Pressure boundary Throttling	Stainless steel	Fuel oil	Loss of material	Chemistry Control Program
Flexible hoses	Pressure boundary	Stainless steel	Fuel oil	Loss of material	Chemistry Control Program
Flame arrestors	Prevent spread of fire	Aluminum	Air/gas	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Oil System (continued)					
External Environment					
Diesel fuel oil storage tanks (Unit 1 only) [VII H1.4.2]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Diesel fuel oil storage tanks (Unit 2 only) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Diesel fuel oil day tanks [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Diesel fuel oil transfer pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Diesel fuel oil pumps (Priming, engine-driven, etc.) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Tubing/fittings Filter housings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Tubing/fittings	Pressure boundary	Bronze Copper	Indoor - not air conditioned	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Oil System (continued)					
External Environment (continued)					
Valves [VII H1.2.1] Piping/fittings [VII H1.1.1] Tubing/fittings [VII I.1.1] Filter housings [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Tubing/fittings Thermowells Flexible hoses	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned	None	None required
Flame arrestors	Prevent spread of fire	Aluminum	Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures) [VII H1.2.2]	Pressure boundary	Carbon steel	Outdoor	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Lube Oil System					
Internal Environment					
Lube oil heat exchanger shells	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Lube oil heat exchanger channel headers (Unit 1 only)	Pressure boundary	Cast iron	Treated water - other	Loss of material	Chemistry Control Program
Lube oil heat exchanger channel headers (Unit 2 only)	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Lube oil heat exchanger tubesheets	Pressure boundary	Brass	Treated water - other	Loss of material	Chemistry Control Program
			Lubricating oil	None	None required
Lube oil heat exchanger tubes	Pressure boundary Heat transfer	Brass	Treated water - other	Loss of material Fouling	Chemistry Control Program
			Lubricating oil	None	None required
Lube oil pumps	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Valves Piping/fittings	Pressure boundary	Carbon steel	Lubricating oil Air/gas	None	None required
Valves	Pressure boundary	Bronze	Lubricating oil	None	None required
Valves Piping/fittings Tubing/fittings Sight glasses	Pressure boundary	Stainless steel	Lubricating oil Air/gas	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Lube Oil System (continued)					
Internal Environment (continued)					
Tubing/fittings Filter housings Expansion joints Thermowells	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Filter housings	Pressure boundary	Aluminum	Lubricating oil	None	None required
Filter elements	Filtration	Carbon steel Brass	Lubricating oil	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Lubricating oil Air/gas	None	None required
Flexible hoses	Pressure boundary	Stainless steel	Lubricating oil	None	None required
Sightglasses	Pressure boundary	Glass	Lubricating oil Air/gas	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Lube Oil System (continued)					
External Environment					
Lube oil heat exchangers [VII I.1.1]	Pressure boundary	Carbon steel Cast iron	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Lube oil pumps [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Tubing/fittings Expansion joints Filter housings Thermowells [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Tubing/fittings Sight glasses	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Valves	Pressure boundary	Bronze	Indoor - not air conditioned	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned	None	None required
Filter housings	Pressure boundary	Aluminum	Indoor - not air conditioned	None	None required

TABLE 3.3-4 (continued)
DIESEL GENERATORS AND SUPPORT SYSTEMS

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Lube Oil System (continued)					
External Environment (continued)					
Sight glasses	Pressure boundary	Glass	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-5
EMERGENCY COOLING CANAL

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves	Pressure boundary	Aluminum bronze	Raw water - salt water	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings	Pressure boundary	Carbon steel	Raw water - salt water	Loss of material	Periodic Surveillance and Preventive Maintenance Program
External Environment					
Valves	Pressure boundary	Aluminum bronze	Raw water - salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings	Pressure boundary	Carbon steel	Raw water - salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Embedded/encased	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Raw water - salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

TABLE 3.3-6
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
City water storage tanks	Pressure boundary	Carbon steel	Air/gas[1] Raw water - city water	Loss of material	Fire Protection Program
Reactor coolant pump oil collection tanks [VII G.7.1]	Pressure boundary	Carbon steel	Air/gas Lubricating oil	None	None required
Unit 1 cable spreading room halon tanks	Pressure boundary	Carbon steel	Air/gas	None	None required
Fire water pumps [VII G.6.2]	Pressure boundary	Cast iron	Raw water - city water	Loss of material	Fire Protection Program
Valves [VII G.6.2] Piping/fittings [VII G.6.1]	Pressure boundary	Cast iron	Raw water - city water	Loss of material	Fire Protection Program
Hydrants [VII G.6.2]	Pressure boundary	Cast iron	Raw water - city water	Loss of material	Fire Protection Program
Hydrants	Pressure boundary	Cast iron	Air/gas	Loss of material	Fire Protection Program
Valves [VII G.7.2] Piping/fittings [VII G.7.2]	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required

NOTES: 1. Potentially humid air due to water in the lower portions of the tanks.

TABLE 3.3-6 (continued)
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves [VII G.6.2] Piping/fittings	Pressure boundary	Copper alloy	Raw water - city water	Loss of material	Fire Protection Program
Valves [VII G.6.2] Piping/fittings [VII G.6.1] Tubing/fittings	Pressure boundary	Stainless steel	Raw water - city water	Loss of material	Fire Protection Program
Valves [VII G.6.2] Piping/fittings [VII G.6.1]	Pressure boundary	Carbon steel	Raw water - city water	Loss of material	Fire Protection Program Galvanic Corrosion Susceptibility Inspection Program
Piping/fittings	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Valves Tubing/fittings	Pressure boundary	Copper alloy	Air/gas	None	None required
Sprinkler heads	Pressure boundary Spray	Copper alloy	Raw water - city water	Loss of material	Fire Protection Program
			Air/gas	None	None required
Nozzles	Pressure boundary Spray	Galvanized carbon steel	Air/gas	None	None required
Hose station - nozzles	Pressure boundary Spray	Copper alloy	Air/gas	None	None required
Hose station - fittings	Pressure boundary	Copper alloy	Air/gas	None	None required

TABLE 3.3-6 (continued)
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Flexible hoses	Pressure boundary	Stainless steel	Lubricating oil Air/gas	None	None required
Drip pans Enclosures	Prevent spread of fire	Stainless steel	Lubricating oil Air/gas	None	None required
Vortex breakers	Vortex prevention	Carbon steel	Raw water - city water	Loss of material	Fire Protection Program
Filters [VII G.6.2]	Filtration	Copper alloy	Raw water - city water	Loss of material	Fire Protection Program
Filters [VII G.6.2]	Filtration	Stainless steel	Raw water - city water	Loss of material	Fire Protection Program
Orifices	Pressure boundary Throttling	Stainless steel	Raw water - city water	Loss of material	Fire Protection Program
Flame arrestors	Prevent spread of fire	Stainless steel Aluminum	Lubricating oil Air/gas	None	None required
Sight glasses	Pressure boundary	Carbon steel Glass	Lubricating oil Air/gas	None	None required

TABLE 3.3-6 (continued)
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
City water storage tanks [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Fire Protection Program
Reactor coolant pump oil collection tanks [VII I.1.1]	Pressure boundary	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Unit 1 cable spreading room halon tanks [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Fire Protection Program
Fire water pumps	Pressure boundary	Cast iron	Outdoor	Loss of material	Fire Protection Program
Valves Piping/fittings Hydrants	Pressure boundary	Cast iron	Outdoor Buried	Loss of material	Fire Protection Program
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Fire Protection Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings Sight glasses [VII I.1.1]	Pressure boundary	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Fire Protection Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.3-6 (continued)
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Valves Piping/fittings Tubing/fittings Hose station - fittings	Pressure boundary	Copper alloy	Outdoor Indoor - not air conditioned	None	None required
Valves Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Valves Tubing/fittings Flexible hoses	Pressure boundary	Stainless steel	Outdoor	None	None required
Piping/fittings	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Piping/fittings	Pressure boundary	Cast iron	Embedded/Encased	None	None required
			Indoor - not air conditioned	Loss of material	Fire Protection Program
Nozzles	Pressure boundary Spray	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Hose station - nozzles Sprinkler heads	Pressure boundary Spray	Copper alloy	Outdoor Indoor - not air conditioned	None	None required
Flexible hoses	Pressure boundary	Stainless steel	Containment air	None	None required
Flame arrestors	Prevent spread of fire	Stainless steel Aluminum	Containment air	None	None required
Drip pans Enclosures	Prevent spread of fire	Stainless steel	Containment air	None	None required

TABLE 3.3-6 (continued)
FIRE PROTECTION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Orifices	Pressure boundary Throttling	Stainless steel	Outdoor	None	None required
Sight glasses	Pressure boundary	Glass	Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Containment air Outdoor Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-7
FUEL POOL COOLING

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Spent fuel pool pumps	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Spent fuel pool heat exchanger tubes[1] (Unit 1 only)	Pressure boundary	Stainless steel	Treated water - borated (inside diameter)	Loss of material	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material	Chemistry Control Program
Spent fuel pool heat exchanger tubes (Unit 2 only)	Pressure boundary Heat transfer	Stainless steel	Treated water - borated (inside diameter)	Loss of material Fouling	Chemistry Control Program
			Treated water - other (outside diameter)	Loss of material Fouling	Chemistry Control Program
Spent fuel pool heat exchanger tubesheets	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
			Treated water - other	Loss of material	Chemistry Control Program
Spent fuel pool heat exchanger channel cylinders and flanges, channel cover facings	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Spent fuel pool heat exchanger shell and tube supports (Unit 2 only) [VII A3.4.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program

NOTES: 1. Heat transfer is not a license renewal intended function for the Unit 1 spent fuel pool heat exchangers (Subsection 2.3.3.7)

TABLE 3.3-7 (continued)
FUEL POOL COOLING

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program

TABLE 3.3-7 (continued)
FUEL POOL COOLING

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Spent fuel pool pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Spent fuel pool heat exchanger channel cylinders and flanges	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Spent fuel pool heat exchanger channel covers [VII A3.4.2]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Spent fuel pool heat exchanger shells (Unit 2 only) [VII A3.4.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures) [VII A3.1.1, A3.3.2, A3.4.3, A3.6.1]	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-8
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Instrument air receivers [VII D.3.1]	Pressure boundary	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Instrument air dryers [VII D.6.1]	Pressure boundary	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Instrument air compressor cooler tubes	Pressure boundary Heat transfer	Copper	Treated water - other	Loss of material Fouling	Chemistry Control Program
			Air/gas[1] (wetted)	Loss of material Fouling	Periodic Surveillance and Preventive Maintenance Program
Instrument air compressor (A and B) cooler tube sheets	Pressure boundary	Copper alloy	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Instrument air compressor (C and D) cooler tube sheets	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Galvanic Corrosion Susceptibility Inspection Program Chemistry Control Program
			Air/gas[1] (wetted)	Loss of material	Galvanic Corrosion Susceptibility Inspection Program Periodic Surveillance and Preventive Maintenance Program

NOTES: 1. Instrument air upstream of the instrument air dryers is considered to be wetted (moist).

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Instrument air compressor cooler shells	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Valves [VII D.2.1, D.4.1] Silencers Accumulators	Pressure boundary	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Strainer housings [VII D.5.1]	Pressure boundary	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program Galvanic Corrosion Susceptibility Inspection Program
Filters	Pressure boundary Filtration	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Filter housings Strainer housings	Pressure boundary	Stainless steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Filters	Filtration	Stainless steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

NOTES: 1. Instrument air upstream of the instrument air dryers is considered to be wetted (moist).

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves	Pressure boundary	Copper alloy Brass Bronze	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Valves	Pressure boundary	Plastic	Air/gas[1] (wetted)	Cracking	Systems and Structures Monitoring Program
Valves Tubing/fittings Thermowells Flexible hoses	Pressure boundary	Stainless steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings [VII D.1.1]	Pressure boundary	Carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program Galvanic Corrosion Susceptibility Inspection Program
Piping/fittings	Pressure boundary	Galvanized carbon steel	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program Galvanic Corrosion Susceptibility Inspection Program
Flexible hoses	Pressure boundary	Rubber	Air/gas[1] (wetted)	Cracking	Systems and Structures Monitoring Program

NOTES: 1. Instrument air upstream of the instrument air dryers is considered to be wetted (moist).

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Sight glasses	Pressure boundary	Copper alloy	Air/gas[1] (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Glass	Air/gas[1] (wetted)	None	None required
Valves	Pressure boundary	Copper alloy Brass Bronze Aluminum	Air/gas	None	None required
Valves Piping/fittings Accumulators	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings Thermowells Flexible hoses Rupture discs Filter housings Strainers	Pressure boundary	Stainless steel	Air/gas	None	None required
Piping/fittings Accumulators	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required

NOTES: 1. Instrument air upstream of the instrument air dryers is considered to be wetted (moist).

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Tubing/fittings	Pressure boundary	Copper	Air/gas	None	None required
Filters	Filtration	Stainless steel	Air/gas	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Air/gas	None	None required

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Instrument air receivers [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Instrument air dryers [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Instrument air compressor cooler shells [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Outdoor Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Flexible hoses Piping/fittings Tubing/fittings Filter housings Strainer housings	Pressure boundary	Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Valves	Pressure boundary	Copper alloy Brass Bronze Aluminum	Indoor - not air conditioned Outdoor	None	None required

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Valves	Pressure boundary	Plastic	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Accumulators [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Accumulators	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Filters Silencers [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Filters [VII I.1.1]	Pressure boundary Filtration	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Rupture discs	Pressure boundary	Stainless steel	Outdoor	None	None required
Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Flexible hoses	Pressure boundary	Rubber	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program

TABLE 3.3-8 (continued)
INSTRUMENT AIR

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Sight glasses	Pressure boundary	Copper alloy Glass	Indoor - not air conditioned	None	None required
Piping/fittings	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned Outdoor	None	None required
Tubing/fittings	Pressure boundary	Copper	Outdoor	None	None required
Strainer housings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Outdoor Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required

TABLE 3.3-9
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Intake cooling water pumps	Pressure boundary	Stainless steel Aluminum bronze	Raw water - salt water	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Basket strainers (shell) [VII C1.6.1]	Pressure boundary	Carbon steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Basket strainers (screen)	Filtration	Stainless steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Valves (main process lines) [VII C1.2.1]	Pressure boundary	Stainless steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Valves (main process lines)	Pressure boundary	Carbon steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Piping/fittings (main process lines) [VII C1.1.1]	Pressure boundary	Stainless steel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Piping/fittings (main process lines)	Pressure boundary	Carbon steel	Raw water - salt water Air/gas[1]	Loss of material	Intake Cooling Water Inspection Program
Valves (strainer bypass, strainer backwash, and spent fuel pool makeup)	Pressure boundary	Carbon steel Cast iron (Unit 1 only)	Raw water - salt water	Loss of material	Systems and Structures Monitoring Program
Piping/fittings (strainer bypass, strainer backwash, and spent fuel pool makeup) [VII C1.1.1]	Pressure boundary	Stainless steel	Raw water - salt water	Loss of material	Systems and Structures Monitoring Program

NOTES 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-9 (continued)
INTAKE COOLING WATER

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

NOTES 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-9 (continued)
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Orifices (Unit 1 only) [VII C1.4.1]	Pressure boundary Throttling	Stainless steel	Raw water - salt water	Loss of material	Systems and Structures Monitoring Program
Orifices	Pressure boundary Throttling	Titanium	Raw water - salt water	None	None required
Orifices	Pressure boundary Throttling	Monel	Raw water - salt water	Loss of material	Intake Cooling Water Inspection Program
Expansion joints (Unit 1 only)	Pressure boundary	Rubber	Raw water - salt water	Cracking	Periodic Surveillance and Preventive Maintenance Program
Expansion joints (Unit 2 only)	Pressure boundary	Stainless steel	Raw water - salt water	Loss of material	Periodic Surveillance and Preventive Maintenance Program

TABLE 3.3-9 (continued)
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Intake cooling water pumps	Pressure boundary	Stainless steel	Indoor - not air conditioned	Loss of material[1]	Periodic Surveillance and Preventive Maintenance Program
			Raw water - salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
		Aluminum bronze	Indoor - not air conditioned	None	None required
			Raw water - salt water (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Basket strainers (shell) [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves	Pressure boundary	Stainless steel Bronze	Outdoor Indoor - not air conditioned	None	None required
		Monel	Outdoor	None	None required
		Aluminum bronze	Indoor - not air conditioned	None	None required
Valves (Unit 1 only)	Pressure boundary	Cast iron	Outdoor	Loss of material	Systems and Structures Monitoring Program

NOTES: 1. Plant experience has identified the potential for intake cooling water pump loss of material due to pitting.

TABLE 3.3-9 (continued)
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Piping/fittings [VII C1.1.2]	Pressure boundary	Carbon steel	Buried	Loss of material	Intake Cooling Water Inspection Program
Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor (ECCS pipe tunnel)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Piping/fittings (discharge)	Pressure boundary	Carbon steel	Raw water - salt water (submerged)	Loss of material	Intake Cooling Water Inspection Program
Piping/fittings	Pressure boundary	Carbon steel	Embedded/encased	None	None required
		Stainless steel	Outdoor Indoor - not air conditioned Buried (Unit 1 only)	None	None required
		Monel	Outdoor Indoor - not air conditioned	None	None required
		Aluminum brass	Outdoor	None	None required
		Aluminum bronze	Indoor - not air conditioned	None	None required
Piping/fittings (Unit 2 only)	Pressure boundary	Fiberglass	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Orifices (Unit 1 only)	Pressure boundary Throttling	Stainless steel	Outdoor	None	None required

TABLE 3.3-9 (continued)
INTAKE COOLING WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Orifices	Pressure boundary Throttling	Monel Titanium	Outdoor Indoor - not air conditioned	None	None required
Tubing/fittings	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned	None	None required
Thermowells	Pressure boundary	Monel	Outdoor Indoor - not air conditioned	None	None required
Expansion joints (Unit 1 only)	Pressure boundary	Rubber	Indoor - not air conditioned	Cracking	Periodic Surveillance and Preventive Maintenance Program
Expansion joints (Unit 2 only)	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned Buried	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program
		Stainless steel Monel	Indoor - not air conditioned	None	None required
			Raw water - salt water (submerged)	Loss of mechanical closure integrity	Periodic Surveillance and Preventive Maintenance Program

TABLE 3.3-10
MISCELLANEOUS BULK GAS SUPPLY

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Vessels	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Piping/fittings	Pressure boundary	Carbon steel Stainless steel	Air/gas	None	None required
Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
External Environment					
Vessels [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves [VII I.1.1] Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-11
PRIMARY MAKEUP WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Primary water storage tank (Unit 2 only)	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
			Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Primary water pumps (Unit 2 only)	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Valves Piping/fittings Tubing/fittings	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Piping (Unit 1 only)	Pressure boundary	Nickel alloy	Treated water - other	Loss of material	Chemistry Control Program
Valves (Unit 2 only)	Pressure boundary	Copper alloy	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Hose station - fittings (Unit 2 only)	Pressure boundary	Copper alloy	Air/gas	None	None required
Hose station - nozzles (Unit 2 only)	Pressure boundary Spray	Copper alloy	Air/gas	None	None required
Orifices (Unit 2 only)	Pressure boundary Throttling	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Expansion joints (Unit 2 only)	Pressure boundary	Rubber	Treated water - other	Cracking	Systems and Structures Monitoring Program

NOTES: 1. Potentially humid air due to water in the lower portions of the tanks.

TABLE 3.3-11 (continued)
PRIMARY MAKEUP WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Vortex breaker (Unit 2 only)	Vortex prevention	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program

TABLE 3.3-11 (continued)
PRIMARY MAKEUP WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Primary water storage tank (Unit 2 only) [VII I.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Primary water storage pumps (Unit 2 only)	Pressure boundary	Stainless steel	Outdoor	None	None required
Valves Piping/fittings	Pressure boundary	Stainless steel	Outdoor Containment air Indoor - not air conditioned	None	None required
Piping/fittings	Pressure boundary	Stainless steel	Embedded/encased	None	None required
Piping/fittings	Pressure boundary	Stainless steel	Outdoor (ECCS pipe tunnel)	Loss of material[1] Cracking[1]	Periodic Surveillance and Preventive Maintenance Program
Piping (Unit 1 only)	Pressure boundary	Nickel alloy	Containment air Indoor - not air conditioned	None	None required
Tubing/fittings	Pressure boundary	Stainless steel	Outdoor	None	None required
Valves (Unit 2 only) Hose station - fittings (Unit 2 only)	Pressure boundary	Copper alloy	Containment air Indoor - not air conditioned	None	None required
Hose station - ozzles (Unit 2 only)	Pressure boundary Spray	Copper alloy	Containment air Indoor - not air conditioned	None	None required

NOTES: 1. Plant experience has identified the potential for SCC and loss of material due to pitting corrosion on stainless steel components located in the ECCS pipe tunnel.

TABLE 3.3-11 (continued)
PRIMARY MAKEUP WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Expansion joints (Unit 2 only)	Pressure boundary	Rubber	Outdoor	Cracking	Systems and Structures Monitoring Program
Orifices	Pressure boundary Throttling	Stainless steel	Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-12
SAMPLING

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Treated water - borated	Loss of material Cracking[1]	Chemistry Control Program
External Environment					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

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

TABLE 3.3-13
SERVICE WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Yard sump pump 2A (Unit 2 only)	Pressure boundary	Stainless steel	Raw water - drains	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Valves Piping/fittings	Pressure boundary	Stainless steel	Raw water - city water	None[1]	None required
Valves (Unit 2 only)	Pressure boundary	Copper alloy	Air/gas (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Piping/fittings (Unit 2 only)	Pressure boundary	Galvanized carbon steel	Air/gas (wetted)	Loss of material	Periodic Surveillance and Preventive Maintenance Program

NOTES: 1. Plant experience confirmed by volumetric examinations have indicated that there are no aging effects requiring management.

TABLE 3.3-13 (continued)
SERVICE WATER

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Yard sump pump 2A (Unit 2 only)	Pressure boundary	Stainless steel	Raw water - drains (submerged)	Loss of material	Periodic Surveillance and Preventive Maintenance Program
			Outdoor (ECCS pipe tunnel)	Loss of material[1] Cracking[1]	Periodic Surveillance and Preventive Maintenance Program
Valves Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Valves (Unit 2 only)	Pressure boundary	Copper alloy	Outdoor	None	None required
Piping/fittings (Unit 2 only)	Pressure boundary	Galvanized carbon steel	Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

NOTES: 1. Plant experience has identified the potential for SCC and loss of material due to pitting corrosion on stainless steel components located in the ECCS pipe tunnel.

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

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Instrument air compressor cooling water head tank	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Instrument air compressor cooling water recirculation pump	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Instrument air fan cooler heads	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Instrument air fan cooler tubes	Pressure boundary Heat transfer	Brass	Treated water - other	Loss of material Fouling	Chemistry Control Program
Valves Piping/fittings Sight glasses	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Thermowells	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Sight glasses	Pressure boundary	Glass	Treated water - other	None	None required

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

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Instrument air compressor cooling water head tank [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Instrument air compressor cooling water recirculation pump [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Instrument air fan cooler heads [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Instrument air fan cooler tubes	Pressure boundary Heat transfer	Brass	Indoor - not air conditioned	None	None required
Instrument air fan cooler fins	Heat transfer	Brass	Indoor - not air conditioned	Loss of material[1] Fouling[1]	Systems and Structures Monitoring Program
Valves Piping/fittings Sight glasses [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Sight glasses	Pressure boundary	Glass	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

NOTES: 1. Plant experience shows a history of loss of material and fouling due to corrosion on fins.

TABLE 3.3-15
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Control Room Air Conditioning					
Internal Environment					
Control room air conditioner heat exchanger condenser shell, vents, drains, baffles, and support plates (Unit 2 only)	Pressure boundary	Carbon steel	Air/gas	None	None required
Control room air conditioner heat exchanger channel, vents, and drains (Unit 2 only)	Pressure boundary	Copper nickel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Control room air conditioner heat exchanger tubes (Unit 2 only)	Pressure boundary Heat transfer	Copper nickel	Treated water - other (inside diameter)	Loss of material Fouling	Chemistry Control Program
			Air/gas (outside diameter)	None	None required
Control room air conditioner heat exchanger tubesheets (Unit 2 only)	Pressure boundary	Copper nickel	Treated water - other	Loss of material	Chemistry Control Program
			Air/gas	None	None required
Valves (Unit 2 only)	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program
Piping/fittings (Unit 2 only) [VII F1.3.1]	Pressure boundary	Carbon steel	Treated water - other	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Control Room Air Conditioning (continued)					
Internal Environment (continued)					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Air/gas	None	None required
Piping/fittings (Unit 2 only)	Pressure boundary	Stainless steel	Treated water - other	Loss of material	Chemistry Control Program
Tubing/fittings	Pressure boundary	Copper	Air/gas	None	None required
Filter housings [VII F1.4.1]	Pressure boundary	Carbon steel	Air/gas	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Ducts [VII F1.1.2]	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Orifices	Pressure boundary Throttling	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F1.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Control Room Air Conditioning (continued)					
External Environment					
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Tubing/fittings	Pressure boundary	Copper	Indoor - not air conditioned	None	None required
Control room air conditioner heat exchanger condenser shell, vents, drains (Unit 2 only) [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Control room air conditioner heat exchanger channel, vents, drains (Unit 2 only)	Pressure boundary	Copper nickel	Indoor - not air conditioned	None	None required
Filter housings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Control Room Air Conditioning (continued)					
External Environment (continued)					
Orifices	Pressure boundary Throttling	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Emergency Core Cooling Systems Area Ventilation					
Internal Environment					
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Air/gas	None	None required
Filter housings Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Orifices	Pressure boundary Throttling	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Emergency Core Cooling Systems Area Ventilation (continued)					
External Environment					
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Filter housings	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Orifices	Pressure boundary Throttling	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fuel Handling Building Ventilation (Unit 2 only)					
Internal Environment					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
External Environment					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Miscellaneous Ventilation (Unit 1 only)					
Internal Environment					
Filter housings Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
External Environment					
Filter housings Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Electrical and Battery Room Ventilation					
Internal Environment					
Shell for HVS-5A and HVS-5B plenum and filters (Unit 1 only)	Pressure boundary	Galvanized carbon steel	Air/gas[1]	Loss of material[2]	Periodic Surveillance and Preventive Maintenance Program
Internal structural supports for HVS-5A and HVS-5B plenum and fans	Structural support	Galvanized carbon steel	Air/gas[1]	Loss of material[2]	Periodic Surveillance and Preventive Maintenance Program
Internal structural supports for HVS-5A and HVS-5B plenum and fans [VII F2.4.1]	Structural support	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Filter holding frames [VII F2.4.1]	Pressure boundary	Stainless steel	Air/gas	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required

NOTES:
1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.
2. Plant experience has identified the potential for loss of material due to general corrosion.

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Electrical and Battery Room Ventilation (continued)					
External Environment					
Unit 1 shell (housing) for HVS-5A and HVS-5B filters Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Filter holding frames	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Main Supply and Exhaust					
Internal Environment					
Shell for HVS-4A and HVS-4B plenum and filters	Pressure boundary	Galvanized carbon steel	Air/gas[1]	Loss of material[2]	Periodic Surveillance and Preventive Maintenance Program
Internal structural supports for HVS-4A and HVS-4B plenum and fans	Structural support	Galvanized carbon steel	Air/gas[1]	Loss of material[2]	Periodic Surveillance and Preventive Maintenance Program
Internal structural supports for HVS-4A and HVS-4B plenum and fans [VII F2.4.1]	Structural support	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Filter holding frames [VII F2.4.1]	Pressure boundary	Stainless steel	Air/gas	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Air/gas	None	None required

NOTES:
1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.
2. Plant experience has identified the potential for loss of material due to general corrosion.

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reactor Auxiliary Building Main Supply and Exhaust (continued)					
External Environment					
Shell (housing) for HVS-4A and HVS-4B filters	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Filter holding frames	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Shield Building Ventilation					
Internal Environment					
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Air/gas	None	None required
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Filter housings [VII F2.4.1]	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Periodic Surveillance and Preventive Maintenance Program
Demisters	Moisture removal	Stainless steel	Air/gas	None	None required
Flexible connections [VII F2.1.3]	Pressure boundary	Rubber coated cloth	Air/gas	Cracking	Systems and Structures Monitoring Program
Tubing/fittings	Pressure boundary	Copper	Air/gas	None	None required
Ducts	Pressure boundary	Galvanized carbon steel	Air/gas	None	None required

NOTES: 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-15 (continued)
VENTILATION

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Shield Building Ventilation (continued)					
External Environment					
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Tubing/fittings	Pressure boundary	Copper	Indoor - not air conditioned	None	None required
Filter housings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Flexible connections	Pressure boundary	Rubber coated cloth	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Ducts	Pressure boundary	Galvanized carbon steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned	None	None required

TABLE 3.3-16
WASTE MANAGEMENT

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Raw water - drains Air/gas	None	None required
Piping	Pressure boundary	Nickel alloy	Air/gas	None	None required
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Cleanout plugs	Pressure boundary	Carbon steel	Air/gas[1]	Loss of material	Systems and Structures Monitoring Program
Cleanout plugs	Pressure boundary	Bronze	Air/gas	None	None required
Strainers	Pressure boundary	Stainless steel	Air/gas	None	None required
Strainer elements	Filtration	Copper alloy	Air/gas	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Air/gas	None	None required

NOTES: 1. Internal air/gas environment is outside air with uncontrolled humidity and temperature.

TABLE 3.3-16 (continued)
WASTE MANAGEMENT

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Valves Piping/fittings	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Piping/fittings	Pressure boundary	Stainless steel	Embedded/encased	None	None required
Piping	Pressure boundary	Nickel alloy	Containment air Indoor - not air conditioned	None	None required
Valves Piping/fittings [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Cleanout plugs [VII I.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Cleanout plugs	Pressure boundary	Bronze	Indoor - not air conditioned	None	None required
Strainers	Pressure boundary	Stainless steel	Indoor - not air conditioned Embedded/encased	None	None required
Strainer elements	Filtration	Copper alloy	Indoor - not air conditioned	None	None required

TABLE 3.3-16 (continued)
WASTE MANAGEMENT

Component/ Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures)	Pressure boundary	Stainless steel	Indoor - not air conditioned Containment air	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Indoor - not air conditioned Containment air	None	None required
			Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

3.4 STEAM AND POWER CONVERSION SYSTEMS

The following systems are included in this section:

- Main Steam, Auxiliary Steam, and Turbine
- Main Feedwater and Steam Generator Blowdown
- Auxiliary Feedwater and Condensate

Subsection 2.3.4 provides a description of these systems and identifies the components requiring an aging management review for license renewal. Appendix C contains the process that identified the aging effects requiring management for non-Class 1 components.

The Steam and Power Conversion Systems scoping, screening, and aging management review results were compared to the GALL Report [Reference 3.4-1]. The following components/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Turbine Piping and Fittings (VIII A.1) - 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.
- Extraction Steam (VIII C) - This system does not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore is not within the scope of license renewal.
- Feedwater Pumps (VIII D1.3) - 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.
- Condensate Systems (VIII E) - The only components from these systems that perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 are the condensate storage tanks and associated components that support the Auxiliary Feedwater Systems. The condensate storage tanks and associated components are included with Auxiliary Feedwater on Table 3.4-3.
- Blowdown Pumps (VIII F.3) - The St. Lucie Unit 1 and 2 designs do not include these components.
- Blowdown Heat Exchangers (VIII F.4) - 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.

For component/commodity groups that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsection 3.4.1. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsection 3.4.4 and detailed in the appropriate subsections of Appendix B. Component/commodity groups identified in Tables 3.4-1 through 3.4-3 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Unit 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

3.4.1 MATERIALS AND ENVIRONMENT

The Steam and Power Conversion Systems are exposed to internal environments of treated water - secondary, lubricating oil, and air/gas; and external environments of outdoor, indoor - not air conditioned, containment air, buried, embedded/encased, and potential borated water leaks (see Tables 3.0-1 and 3.0-2). For corresponding component/commodity groups included in the GALL Report, FPL identified air/gas and lubricating oil as additional internal environments for valves, piping, and fittings; and air/gas as an additional internal environment for the condensate storage tanks at St. Lucie Units 1 and 2.

The tanks, pumps, heat exchangers, piping, tubing, valves, and associated components and commodity groups for these systems are constructed of carbon steel, stainless steel, nickel alloy, and glass. The components and commodity groups, their intended functions, the materials, and environments for the Steam and Power Conversion Systems are summarized in Tables 3.4-1 through 3.4-3. For corresponding component/commodity groups included in the GALL Report, FPL identified stainless steel as an additional material for valves, piping, and fittings at St. Lucie Units 1 and 2.

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 aging management review process; see Table 3.0-2, "External Service Environments." Potential aging effects associated with these environments are reviewed and those aging effects requiring management are identified along with the credited aging management program(s). All other parts of systems and components can be accessed, if required. The only Steam and Power Conversion System containing inaccessible piping parts is Auxiliary Feedwater, which contains sections of buried and embedded stainless steel piping.

3.4.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects requiring management and the programs and activities that manage the aging effects for each applicable environment and material combination are provided in Tables 3.4-1 through 3.4-3. The aging effects requiring management for each system are summarized in the following paragraphs.

<u>Main Steam, Auxiliary Steam, and Turbines</u> - 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. Note that 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 Subsection 4.3.2.

<u>Main Feedwater and Steam Generator Blowdown</u> - 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. Note that 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 Subsection 4.3.2.

<u>Auxiliary Feedwater and Condensate</u> - The aging effects requiring management are loss of material for carbon steel and stainless steel components. Note that 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 Subsection 4.3.2.

3.4.3 OPERATING EXPERIENCE

3.4.3.1 INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Steam and Power Conversion Systems includes the following:

- NRC Bulletin 79-13, "Cracking in Feedwater System Piping"
- NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants"
- NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Generic Letter 79-20, "Information Requested on PWR Feedwater Lines"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning"
- NRC Generic Letter 91-17, "Generic Issue 29, Bolting Degradation or Failure in Nuclear Power Plants"
- NRC Information Notice 80-29, "Broken Studs on Terry Turbine Steam Inlet Flanges"
- NRC Information Notice 81-04, "Cracking in Main Steam Lines"
- NRC Information Notice 81-38, "Potentially Significant Equipment Failures Resulting from Contamination of Air-Operated Systems"
- NRC Information Notice 82-22, " Failures in Turbine Exhaust Lines"
- NRC Information Notice 84-32, "Auxiliary Feedwater Sparger and Pipe Hanger Damage"
- NRC Information Notice 84-87, "Piping Thermal Deflection Induced by Stratified Flow"
- NRC Information Notice 86-106, "Feedwater Line Break"
- NRC Information Notice 87-36, "Significant Unexpected Erosion of Feedwater Lines"
- NRC Information Notice 88-17, "Summary of Responses to NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants"
- NRC Information Notice 88-37, "Flow Blockage of Cooling Water to Safety System Components"
- NRC Information Notice 88-87, "Pump Wear and Foreign Objects in Plant Piping Systems"
- NRC Information Notice 89-01, "Valve Body Erosion"
- NRC Information Notice 90-65, "Recent Orifice Plate Problems"

- NRC Information Notice 91-18, "High-Energy Piping Failures Caused by Wall Thinning"
- NRC Information Notice 91-38, "Thermal Stratification in Feedwater System Piping"
- NRC Information Notice 93-20, "Thermal Fatigue Cracking of Feedwater Piping to Steam Generators"
- NRC Information Notice 93-21, "Summary of Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs"
- NRC Information Notice 95-11, "Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device"
- NRC Information Notice 97-84, " Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion"
- NRC Information Notice 99-19, "Rupture of the Shell Side of a Feedwater Heater at the Point Beach Plant"
- NRC Information Notice 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.4.2.

3.4.3.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Steam and Power Conversion Systems component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.4.2.

3.4.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.4.2. Tables 3.4-1 through 3.4-3 contain the results of the aging management review for the Steam and Power Conversion Systems and summarize the aging effects requiring management.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program

St. Lucie plant-specific programs:

- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Condensate Storage Tank Cross Connect Buried Pipe Inspection
- Pipe Wall Thinning Inspection Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Steam and Power Conversion Systems components listed in Tables 3.4-1 through 3.4-3 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.4.5 REFERENCES

3.4-1 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

TABLE 3.4-1
MAIN STEAM, AUXILIARY STEAM, AND TURBINE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Valves [VIII A.2.1] [VIII B1.2.1] Piping/fittings [VIII B1.1.1 - B1.1.6]	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
Valves Tubing/fittings Thermowells	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Steam traps	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
		Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Strainer housings	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
Strainer elements	Filtration	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program

TABLE 3.4-1 (continued)
MAIN STEAM, AUXILIARY STEAM, AND TURBINE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Orifices	Pressure boundary Throttling	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
Orifices[1]	Throttling	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
		Nickel alloy	Treated water - secondary	Loss of material Cracking	Chemistry Control Program

NOTES: 1. The stainless steel and nickel alloy orifice components are internal inserts and do not have a pressure boundary function.

TABLE 3.4-1 (continued)
MAIN STEAM, AUXILIARY STEAM, AND TURBINE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Valves Piping/fittings [VIII H.1.1]	Pressure boundary	Carbon steel	Containment air Indoor - not air conditioned Outdoor	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Piping/fittings [VIII H.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material[2]	Flow Accelerated Corrosion Program[3]
Strainer housings [VIII H.1.1]	Pressure boundary	Carbon steel	Indoor - not air conditioned	None[1]	None required
Valves Tubing/fittings	Pressure boundary	Stainless steel	Containment air Indoor - not air conditioned Outdoor	None	None required
Thermowells	Pressure boundary	Stainless steel	Outdoor	None	None required
Steam traps [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Steam traps	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned	None	None required

NOTES:
1. Carbon steel components that normally operate at high temperatures are not susceptible to loss of material (see Appendix C).
2. Applies to various drain lines isolated from high operating temperatures.
3. Flow Accelerated Corrosion Program addresses external general corrosion via use of radiographic examinations.

TABLE 3.4-1 (continued)
MAIN STEAM, AUXILIARY STEAM, AND TURBINE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Orifices [VIII H.1.1]	Pressure boundary Throttling	Carbon steel	Containment air	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Bolting (mechanical closures) [VIII H.2.1]	Pressure boundary	Carbon steel	Containment air Indoor - not air conditioned Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

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

TABLE 3.4-2
MAIN FEEDWATER AND STEAM GENERATOR BLOWDOWN

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Main feedwater isolation valve accumulators hydraulic end (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil	Loss of material[1]	Periodic Surveillance and Preventive Maintenance Program Galvanic Corrosion Susceptibility Inspection Program
Main feedwater isolation valve accumulators pneumatic end (Unit 2 only)	Pressure boundary	Carbon steel	Air/gas[2]	None	None required
Valves [VIII D1.2.1] Piping/fittings [VIII F.1.1 and F.1.2]	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program Galvanic Corrosion Susceptibility Inspection Program
Valves [VIII F.2.1] Piping/fittings [VIII D1.1.1]	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Flow Accelerated Corrosion Program
Valves	Pressure boundary	Carbon steel	Lubricating oil	Loss of material[1]	Periodic Surveillance and Preventive Maintenance Program

NOTES:
1. Plant experience has identified the potential for loss of material due to lubricating oil moisture contamination.
2. Main feedwater isolation valve accumulators utilize high purity nitrogen.

TABLE 3.4-2 (continued)
MAIN FEEDWATER AND STEAM GENERATOR BLOWDOWN

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves Tubing/fittings	Pressure boundary	Stainless steel	Lubricating oil	Loss of material[1]	Periodic Surveillance and Preventive Maintenance Program
Valves Thermowells Tubing/fittings	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program
Valves Tubing/fittings	Pressure boundary	Stainless steel	Air/gas[2]	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Treated water - secondary	Loss of material Cracking	Chemistry Control Program

NOTES:
1. Plant experience has identified the potential for loss of material due to lubricating oil moisture contamination.
2. Main feedwater isolation valve accumulators and associated valves, tubing, and fittings utilize high purity nitrogen.

TABLE 3.4-2 (continued)
MAIN FEEDWATER AND STEAM GENERATOR BLOWDOWN

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Main feedwater isolation valve accumulators (Unit 2 only) [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings [VIII H.1.1]	Pressure boundary	Carbon steel	Containment air Indoor - not air conditioned Outdoor	None[1]	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Valves Tubing/fittings	Pressure boundary	Stainless steel	Containment air Indoor - not air conditioned Outdoor	None	None required
Orifices	Pressure boundary Throttling	Stainless steel	Indoor - not air conditioned	None	None required
Thermowells	Pressure boundary	Stainless steel	Indoor - not air conditioned	None	None required
Bolting (mechanical closures) [VIII H.2.1]	Pressure boundary	Carbon steel	Containment air Indoor - not air conditioned Outdoor	None	None required
Bolting (mechanical closures)	Pressure boundary	Carbon steel	Borated water leaks	Loss of mechanical closure integrity	Boric Acid Wastage Surveillance Program

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

TABLE 3.4-3
AUXILIARY FEEDWATER AND CONDENSATE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment					
Condensate storage tanks [VIII G.4.1]	Pressure boundary	Carbon steel	Air/gas[1]	None	None required
			Treated water - secondary	Loss of material	Chemistry Control Program
Auxiliary feedwater pumps [VIII G.2.1]	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program
Auxiliary feedwater turbines	Pressure boundary	Carbon steel	Air/gas (Unit 1 only)	None	None required
			Treated water - secondary[2] (Unit 2 only)	None	None required
Auxiliary feedwater lube oil tanks (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Lube oil pump (Unit 2 only)	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Lube oil cooler (Unit 2 only) shell [VIII G.5.1]	Pressure boundary	Carbon steel	Lubricating oil	None	None required
Lube oil cooler (Unit 2 only) channel head	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program Galvanic Corrosion Susceptibility Inspection Program

NOTES:
1. A nitrogen blanket is maintained inside each Condensate Storage Tank.
2. The Unit 2 Auxiliary Feedwater Pump Turbine is maintained with limited amount of bypass steam flow during standby operation.

TABLE 3.4-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Lube oil cooler (Unit 2 only) tubes [VIII G.5.2]	Heat transfer Pressure boundary	Stainless steel	Treated water - secondary (inside diameter)	Loss of material	Chemistry Control Program
			Lubricating oil (outside diameter)	None	None required
Lube oil cooler (Unit 2 only) tube sheet [VIII G.5.3]	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material	Chemistry Control Program
			Lubricating oil	None	None required
Valves [VIII G.3.1] Piping/fittings [VIII G.1.1]	Pressure boundary	Carbon steel	Treated water - secondary	Loss of material	Chemistry Control Program
					Galvanic Corrosion Susceptibility Inspection Program
Valves Tubing/fittings	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material	Chemistry Control Program
Piping/fittings	Pressure boundary	Stainless steel	Treated water - secondary	Loss of material	Chemistry Control Program Pipe Wall Thinning Inspection Program[1]
Valves Piping/fittings	Pressure boundary	Carbon steel	Lubricating oil	None	None required

NOTES: 1. Plant experience has identified the potential for loss of material due to erosion of the stainless steel pipe downstream of the recirculation orifices due to localized high flow velocities.

TABLE 3.4-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
Internal Environment (continued)					
Valves Piping/fittings	Pressure boundary	Carbon steel	Air/gas	None	None required
Sightglasses	Pressure boundary	Glass	Lubricating oil Air/gas	None	None required
		Carbon Steel	Lubricating oil Air/gas	None	None required
Vortex breakers	Vortex prevention	Carbon steel	Treated water-secondary	Loss of material	Chemistry Control Program
Orifices	Pressure boundary Throttling	Stainless steel	Treated water-secondary	Loss of material	Chemistry Control Program

TABLE 3.4-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment					
Unit 1 condensate storage tank [VIII G.4.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Unit 2 condensate storage tank	Pressure boundary	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Auxiliary feedwater pumps [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Auxiliary feedwater turbines [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Lube oil tanks (Unit 2 only) [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Lube oil pump (Unit 2 only) [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Lube oil cooler (Unit 2 only) [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Valves Piping/fittings	Pressure boundary	Stainless steel	Outdoor Indoor - not air conditioned	None	None required

TABLE 3.4-3 (continued)
AUXILIARY FEEDWATER AND CONDENSATE

Component / Commodity Group [GALL Reference]	Intended Function	Material	Environment	Aging Effects Requiring Management	Program/Activity
External Environment (continued)					
Piping/fittings	Pressure boundary	Stainless steel	Buried[1]	Loss of material	Condensate Storage Tank Cross Connect Buried Pipe Inspection
Piping/fittings	Pressure boundary	Stainless steel	Buried[2] Embedded/encased[2]	None	None required
Tubing/fittings	Pressure boundary	Stainless steel	Outdoor	None	None required
Sightglasses	Pressure boundary	Glass	Outdoor	None	None required
Sightglasses [VIII H.1.1]	Pressure boundary	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Orifices	Pressure boundary Throttling	Stainless steel	Outdoor	None	None required
Bolting (mechanical closures) [VIII H.2.1]	Pressure boundary	Carbon steel	Outdoor Indoor - not air conditioned	None	None required

NOTES:
1. Condensate storage tank cross-connect piping is susceptible to wetting.
2. 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.

3.5 STRUCTURES AND STRUCTURAL COMPONENTS

Structures and their structural components and commodities that are within the scope of license renewal and subject to aging management reviews are discussed in Section 2.4 and summarized in Tables 3.5-2 through 3.5-16.

The determination of the aging effects applicable to structures and their structural components and commodities begins with the identification of the aging effects defined in industry literature. From this set of aging effects, the component and commodity materials and operating environments define the aging effects for each structural component or commodity that is subject to an aging management review. These aging effects are validated by a review of industry and St. Lucie Units 1 and 2 operating experiences to provide reasonable assurance that the full set of aging effects are established for the aging management review.

The Structures and Structural Components scoping and screening results were compared to the GALL Report [Reference 3.5-1]. The following component/commodity groups identified in the GALL Report do not require an aging management review for St. Lucie Units 1 and 2 for the reasons noted.

- Block walls at the Intake Structures (III.A6.3-a) - The St. Lucie design does not contain these components.
- Class 1 Support High Strength Bolting (III.B1.1.2-a) - The St. Lucie design does not contain these components.
- New Fuel Racks (VII.A.1) - These components do not perform or support any license renewal system intended function that satisfy the scoping criteria of 10 CFR 54.4 and therefore, are not within the scope of license renewal.

For components that require an aging management review that are also included in the GALL Report, differences in materials and environments are described in Subsections 3.5.1 and 3.5.2. Aging management programs that are consistent with the GALL Report and those that are plant specific are identified in Subsections 3.5.1 and 3.5.2 and detailed in the appropriate subsections of Appendix B. Component/commodity groups identified in Tables 3.5-2 through 3.5-16 provide a GALL Report reference in brackets, where applicable, indicating that the St. Lucie Units 1 and 2 component/commodity group, material, and environment are the same. If no GALL Report reference is included, the component/commodity group is plant specific.

Structural components inaccessible for inspection were evaluated for potential aging effects based on their environment as part of the aging management review. Several structural components that are inaccessible for visual inspection require aging management at St. Lucie. Examples include buried concrete, embedded steel, and structural components blocked by installed equipment or structures. Structural components inaccessible for inspection are managed by inspecting accessible structures with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components. The programs credited for managing aging effects of inaccessible structural components are the ASME Section XI, Subsection IWE Inservice Inspection

Program and the Systems and Structures Monitoring Program. These programs are discussed in Appendix B.

3.5.1 CONTAINMENTS

The Containment structures and structural components are grouped into four classifications:

- Containment steel in air structural components
- Containment steel in fluid structural components
- Containment concrete structural components
- Containment miscellaneous structural components

3.5.1.1 CONTAINMENT STEEL IN AIR STRUCTURAL COMPONENTS

Containment steel in air structural components include:

- containment vessels (including attachments)
- component supports
- maintenance, personnel, and escape hatches, including hinges, latches, and equalizing valves (Note that active components such as interlocks and operating mechanisms do not require an aging management review)
- penetrations (including mechanical, heating and ventilation, and steel pressure boundary portions of the electrical penetration assemblies)
- fuel transfer tube flanges and sleeves
- cranes and hoists
- conduits and cable trays
- electrical and instrument panels and enclosures
- supports (including conduit and cable tray, electrical and instrument panels and enclosures, HVAC ducts, safety-related and non-safety related piping, and tubing)
- non-safety related piping between class break and anchor
- pipe whip restraints
- sump screens
- structural steel (columns, beams, etc.)
- miscellaneous steel (radiation shielding, missile barriers, hatch frame covers)
- stairs, ladders, platforms, handrails, checkered plate, and grating

3.5.1.1.1 MATERIALS AND ENVIRONMENT

Containment steel in air structural components were designed and constructed in accordance with American Institute of Steel Construction (AISC) standards. The codes and standards used for the design and fabrication are identified in Unit 1 UFSAR Section 3.8, and Unit 2 UFSAR Section 3.8. Containment steel in air structural components are constructed of carbon steel, galvanized carbon steel, nickel alloy, and stainless steel. St. Lucie Containment steel in air structural components are exposed to environments of containment air, outdoor, indoor - not air conditioned, and potential borated water leaks (see Table 3.0-2). The specific materials and environments for steel in air structural components for Containments are contained in Table 3.5-2. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

Pipe segments beyond the safety-related/non-safety related boundaries are constructed of carbon steel and stainless steel and consist of piping and inline components. The external surfaces of these pipe segments are exposed to the Containment air environment and potential borated water leaks. Internal environments of the pipe segments are the same as the internal environments for the systems in which the pipe segments are installed.

3.5.1.1.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of the intended function(s) for Containment steel in air structural components are loss of material, cracking, and change in material properties. Each is discussed below.

LOSS OF MATERIAL

Aging mechanisms that can lead to loss of material of Containment steel in air structural components are mechanical wear, corrosion, and aggressive chemical attack. This may be seen as material dissolution, corrosion product buildup, and pitting. Loss of material may be uniform or localized.

Mechanical wear is associated with close-fitting mechanical components having relative motion and is not applicable to structural steel. Accordingly, mechanical wear is not an aging mechanism that can lead to loss of material in Containment steel in air structural components.

Loss of material in steel may be caused by corrosion. Carbon steel in an air environment is susceptible to corrosion except under the following conditions: steel located in an air conditioned environment, or steel which is galvanized and not wetted. Stainless steel structural components are not subject to corrosion in the containment air environments at St. Lucie Nuclear Plant. Accordingly, with the exceptions above, corrosion is an aging mechanism that can lead to loss of material in selected Containment steel in air structural components.

Aggressive chemical attack due to boric acid is an aging mechanism for Containment steel in air structural components. This form of corrosion is typically localized and is a result of leakage from borated water systems that can concentrate boric acid and lead to significant material loss of carbon steel and galvanized carbon steel components. Although this type of corrosion is event driven (boric acid leaks), boric acid corrosion was evaluated as an aging mechanism at St. Lucie.

Based on the above, loss of material due to corrosion and aggressive chemical attack is an aging effect requiring management for selected Containment steel in air structural components.

CRACKING

Aging mechanisms that can lead to cracking of Containment steel in air structural components are SCC and fatigue.

SCC is an age-related degradation mechanism that affects stainless steels but becomes significant only if tensile stresses and a corrosive environment exist. The stresses may be either applied (external) or residual (internal). The stress corrosion cracks themselves may be either transgranular or intergranular, depending upon the metal and the corrosive agent. As is normal in all cracking, the cracks are perpendicular to the tensile stress. Usually there is little or no obvious visual evidence of corrosion. In order for SCC to occur, an unfavorable environment, such as wetted surfaces, must be present. Since the only wetted surfaces are a result of event-driven incidents, such as boric acid leakage, SCC is not an aging mechanism that can lead to cracking for Containment steel in air structural components.

Fatigue is a progressive degradation problem for materials subjected to cyclic application of loads that are less than the maximum allowable static loads. For steel components, fatigue is the cumulative effect of microstructural localized plastic deformation in the material section that results each time a stress cycle of sufficient magnitude occurs. Cracking resulting from fatigue is typically controlled by design. The analyses of metal fatigue are discussed in Chapter 4 on Time-Limited Aging Analyses (TLAA). Fatigue of the Containment vessel is evaluated in Section 4.5. Fatigue of penetrations is evaluated as a TLAA in Subsection 4.5.2. Fatigue of various cranes is evaluated as a TLAA in Subsection 4.6.2. These evaluations conclude that fatigue is not an aging mechanism that can lead to cracking at St. Lucie Units 1 and 2.

Based on the above, cracking is not an aging effect requiring management for Containment steel in air structural components.

CHANGE IN MATERIAL PROPERTIES

Aging mechanisms that can cause change in material properties for Containment steel in air structural components are thermal embrittlement, irradiation embrittlement, creep, and stress relaxation.

Thermal embrittlement is a mechanism by which the mechanical property fracture toughness is affected as a result of exposure to elevated temperature. Cast austenitic stainless steel (CASS) materials are susceptible to thermal embrittlement dependent upon material composition and the time at temperature. However, CASS materials are not used in the Containment steel in air structural components that could potentially be exposed to high temperatures. Therefore, thermal embrittlement is not an aging mechanism that can lead to change in material properties for Containment steel in air structural components.

Irradiation embrittlement was evaluated as an aging mechanism for Containment steel in air structural components that could lead to change in material properties. Shielding from the water in the reactor core and the reactor vessel reduces the neutron flux, resulting in levels of accumulated exposure that are far below the levels necessary to cause degradation. The maximum gamma dose evaluated through the period of extended operation is below the dose required for radiation degradation. Therefore, irradiation embrittlement is not an aging mechanism that can lead to change in material properties for Containment steel in air structural components.

The effects of low fracture toughness and lamellar tearing have been identified as an industry issue in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generator and Reactor Coolant Pump Supports." NUREG-0577 states that a risk evaluation was performed and the results are incorporated in a value-impact analysis. The NUREG concluded that requirements to certify the acceptability of material or design should not be imposed. Therefore, such actions would provide no safety benefit. FPL Letter L-77-349 [Reference 3.5-2] stated that the fracture toughness data for the St. Lucie Units 1 and 2 steam generator and reactor coolant pump support structure materials were conservatively compared to the fracture toughness properties identified in NUREG-0577 and deemed acceptable. St. Lucie was not required to demonstrate that steel components in the Reactor Coolant System supports have sufficient fracture toughness to perform their intended functions. Therefore, low fracture toughness and lamellar tearing is not an aging effect that can lead to change in material properties for Containment steel in air structural components.

Per Appendix C, creep and stress relaxation are not aging mechanisms that can lead to change in material properties for Containment steel in air structural components.

Based on the above, change in material properties is not an aging effect requiring management for Containment steel in air structural components.

3.5.1.1.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Containment steel in air structural components includes the following:

- NRC Bulletin 88-05, "Nonconforming Materials Supplied by Piping Supplies, Inc. and West Jersey Manufacturing Company"
- NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to the Reactor Coolant System"
- NRC Generic Letter 80-08, "Examination of Containment Liner Penetration Welds"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 98-04, "Potential Degradation of the Emergency Core Cooling System and Containment Spray System after a Loss of Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in the Containment"
- NRC Information Notice 86-99, "Degradation of Steel Containments"

- NRC Information Notice 89-79, "Degraded Coatings and Corrosion of Steel Containment Vessels"
- NRC Information Notice 89-80, "Potential For Water Hammer, Thermal Stratification, and Steam Binding in High Pressure Coolant Injection Piping"
- NRC Information Notice 93-25, "Electrical Penetration Assembly Degradation"
- NRC Information Notice 97-10, "Liner Plate Corrosion in Concrete Containments"
- NRC Information Notice 97-13, "Deficient Conditions Associated with Protective Coatings at Nuclear Power Plants"
- NUREG-0577, Revision 1, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generator and Reactor Coolant Pump Supports"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.1.1.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Containment steel in air structural component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.1.1.2.

3.5.1.1.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.1.1.2. Table 3.5-2 contains the results of the aging management review for the Containments and summarizes the aging effects requiring management for Containment steel in air structural components.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program

St. Lucie plant-specific programs:

- Systems and Structures Monitoring Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the Containment steel in air structural components listed in Table 3.5-2 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.1.2 CONTAINMENT STEEL IN FLUID STRUCTURAL COMPONENTS

This subsection includes Containment steel structural components that are exposed to fluids and those Containment steel structural components that are exposed to both fluids and air. Containment steel structural components that are exposed to only an air environment were discussed in Subsection 3.5.1.1 above. Containment steel in fluid structural components include:

- fuel transfer tubes and expansion bellows
- reactor cavity liner plates
- reactor cavity seal rings

3.5.1.2.1 MATERIALS AND ENVIRONMENT

Containment steel in fluid structural components were designed and constructed in accordance with AISC standards. The codes and standards used for the design and fabrication of the Containment steel in fluid structural components are identified in Unit 1 UFSAR Section 3.8, and Unit 2 UFSAR Section 3.8.

Containment steel in fluid structural components are constructed of stainless steel.

St. Lucie steel in fluid structural components are exposed to a fluid environment of treated water - borated, and an air environment of containment air (see Tables 3.0-1 and 3.0-2). The specific materials and environments for Containment steel in fluid structural components are contained in Table 3.5-2. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.1.2.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for Containment steel in fluid structural components are loss of material, cracking, and change in material properties. The aging mechanisms that could lead to these aging effects in Containment steel in fluid structural components were evaluated using the methodology provided in Appendix C. The results are provided below.

<u>LOSS OF MATERIAL</u>

Aging mechanisms that can lead to loss of material of Containment steel in fluid structural components are corrosion (general, galvanic, crevice, pitting, erosion-corrosion, microbiologically influenced corrosion, and leaching), wear, and aggressive chemical attack.

Based on the evaluation using the methodology described in Appendix C, wear, aggressive chemical attack, and corrosion due to general, galvanic, crevice, erosion-corrosion, microbiologically influenced corrosion, and leaching are not aging mechanisms that can lead to loss of material in Containment steel in fluid structural components exposed to treated water - borated. However, loss of material due to pitting corrosion is an aging effect requiring management for Containment steel in fluid structural components exposed to treated water - borated.

Based on the above, loss of material due to pitting corrosion is an aging effect requiring management for Containment steel in fluid structural components.

CRACKING

Aging mechanisms that can lead to cracking of Containment steel in fluid structural components are SCC, IGA, and fatigue.

Based on the evaluation using the methodology described in Appendix C, SCC, IGA, and fatigue were evaluated for Containment steel in fluid structural components at St. Lucie and determined not to lead to cracking requiring management. Accordingly, cracking is not an aging effect requiring management for Containment steel in fluid structural components.

CHANGE IN MATERIAL PROPERTIES

Aging mechanisms that can cause change in material properties of Containment steel in fluid structural components are thermal embrittlement and irradiation embrittlement.

Thermal embrittlement is a mechanism by which the mechanical property fracture toughness is affected as a result of exposure to elevated temperature. Cast austenitic stainless steel (CASS) materials are susceptible to thermal embrittlement dependent upon material composition and the time at temperature. However, the Containment steel in fluid structural components are not exposed to high temperatures. Therefore, thermal embrittlement is not an aging mechanism that can lead to change in material properties for Containment steel in fluid structural components.

Irradiation embrittlement was evaluated as an aging mechanism for Containment steel in fluid structural components that could lead to change in material properties. Shielding from the water in the reactor core and the reactor vessel reduces the neutron flux, resulting in levels of accumulated exposure that are far below the levels necessary to cause degradation. The maximum gamma dose evaluated through the period of extended operation is below the dose required for radiation degradation. Therefore, irradiation embrittlement is not an aging mechanism that can lead to change in material properties for Containment steel in fluid structural components.

Based on the above, change in material properties is not an aging effect requiring management for Containment steel in fluid structural components.

3.5.1.2.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Containment steel in fluid structural components includes the following:

- NRC Bulletin 94-01, "Potential Fuel Pool Draindown Caused by Inadequate Maintenance Practices at Dresden Unit 1"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.1.2.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Containment steel in fluid structural component aging, in addition to interviews with responsible engineering personnel. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.1.2.2.

3.5.1.2.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.1.2.2. Table 3.5-2 contains the results of the aging management review for the Containments and summarizes the aging effects requiring management for Containment steel in fluid structural components.

The aging effects requiring management are adequately managed by the following program:

St. Lucie program consistent with the corresponding program in the GALL Report:

- Chemistry Control Program

Based on the evaluation provided in Appendix B for the program listed above, aging effects are adequately managed so that the intended functions of the Containment steel in fluid structural components listed in Table 3.5-2 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.1.3 CONTAINMENT CONCRETE STRUCTURAL COMPONENTS

Containment concrete structural components include:

- exterior and interior walls
- beams, slabs, domes, and foundations
- missile shields

- equipment pads
- masonry block walls

Note: Reinforcing steel and embedded steel are evaluated with the concrete components.

3.5.1.3.1 MATERIALS AND ENVIRONMENT

Containment concrete structural components were designed and constructed in accordance with American Concrete Institute (ACI) and ASTM standards. The St. Lucie Units 1 and 2 containments do not have a porous concrete sub-foundation. The codes and standards used for the design and fabrication of the Containment concrete structural components are identified in Unit 1 UFSAR Section 3.8, and Unit 2 UFSAR Section 3.8.

St. Lucie Containment concrete structural components are exposed to environments of containment air, outdoor, and buried (see Table 3.0-2). The specific materials and environments for Containment concrete structural components for each structure are contained in Table 3.5-2. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.1.3.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for Containment concrete structural components are loss of material, cracking, and change in material properties. Each is discussed below.

<u>LOSS OF MATERIAL</u>

Loss of material is manifested in Containment concrete structural components as scaling, spalling, pitting, and erosion. Aging mechanisms that can lead to loss of material are freeze-thaw, abrasion and cavitation, elevated temperature, aggressive chemical attack, and corrosion of reinforcing and embedded/encased steel.

Freeze-thaw is considered an aging mechanism for Containment concrete structural components that are exposed to severe weather conditions of numerous freeze-thaw cycles with significant amounts of winter rainfall. St. Lucie Nuclear Plant is located in a subtropical climate with long, warm summers accompanied by abundant rainfall and mild, dry winters with negligible freeze-thaw cycles. Therefore, freeze-thaw is not an aging mechanism that can lead to loss of material for Containment concrete structural components.

Abrasion and cavitation is an aging mechanism that occurs only in concrete structures that are continually exposed to flowing water. The Containment concrete structural components are not subjected to flowing water. Therefore, abrasion and cavitation is not an aging mechanism that can lead to loss of material for Containment concrete structural components.

Elevated temperature was evaluated as an aging mechanism for Containment concrete structural components. Localized hotspots are limited in area and are designed to be maintained below the degradation threshold temperature limits of the ACI standards. Therefore, elevated temperature is not an aging mechanism that can lead to loss of material for Containment concrete structural components.

Aggressive chemical attack, leading to corrosion of reinforcing steel and embedded steel, was identified as an age-related degradation mechanism for Containment concrete structural components. At St. Lucie Units 1 and 2, this is applicable to Containment concrete structural components exposed to the groundwater.

Based on the above, loss of material due to aggressive chemical attack leading to corrosion of reinforcing and embedded steel is an aging effect that requires aging management for Containment concrete structural components below groundwater elevation.

CRACKING

Cracking is manifested in concrete structural components as complete or incomplete separation of the concrete into two or more parts. Aging mechanisms that can lead to cracking of Containment concrete structural components are freeze-thaw, reactions with aggregates, shrinkage, settlement, fatigue, and elevated temperature.

As discussed previously, freeze-thaw is not an aging mechanism that can lead to cracking for Containment concrete structural components at St. Lucie Nuclear Plant.

St. Lucie concrete components were constructed using non-reactive aggregates whose acceptability was based on established industry standards and ASTM tests. Therefore, reaction with aggregates is not an aging mechanism that can lead to cracking for Containment concrete structural components.

When concrete is exposed to air, large portions of the free water evaporate, causing shrinkage. At St. Lucie, low slump concrete was used and adequate steel reinforcement was provided, which minimize shrinkage. Based on industry information, 100% of concrete shrinkage occurs within 20 years. St. Lucie concrete structures and concrete components were constructed 18 to 25 years or more ago; therefore, concrete shrinkage is not an aging mechanism that can lead to cracking for Containment concrete structural components.

Settlement is based directly on the physical properties of a structure's foundation material. The most pronounced settlement is evidenced in the first several months after construction. St. Lucie concrete structures are founded on compacted Class I fill consisting of clean sand and gravel with a maximum of 12% fines. After initial settlement occurred, the settlement ceased, no further significant settlement has occurred, and no further significant structural settlement is expected. Therefore, settlement is not an aging mechanism that can lead to cracking for Containment concrete structural components.

Fatigue is a progressive degradation problem for materials subjected to cyclic application of loads that are less than the maximum allowable static loads. St. Lucie concrete components are designed in accordance with ACI standards and have good low-cycle fatigue properties. Although some concrete components are subject to high cycles of low-level repeated load, these components were designed in accordance with ACI standards, which limit the maximum design stress to less than 50% of the static stress of the concrete. Therefore, fatigue is not an aging mechanism that can lead to cracking for Containment concrete structural components.

As discussed previously, Containment concrete structural components are not exposed to elevated temperatures that exceed ACI threshold limits and, therefore, elevated temperature is not an aging mechanism that can lead to cracking for Containment concrete structural components.

Based on the above, cracking is not an aging effect requiring management for Containment concrete structural components.

CHANGE IN MATERIAL PROPERTIES

Change in material properties is manifested in concrete as increased permeability, increased porosity, reduction in pH, reduction in tensile strength, reduction in compressive strength, reduction in modulus of elasticity, and reduction in bond strength. Aging mechanisms that can lead to a change in material properties of Containment concrete structural components are leaching, creep, elevated temperature, irradiation embrittlement, and aggressive chemical attack.

Leaching of calcium hydroxide is observed on concrete that is alternately wetted and dried. White deposits that are left on the surface of the concrete are a solution of water, free lime from the concrete, and carbon dioxide that is readily seen on the surface of the concrete. St. Lucie concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the guidance provided by the ACI, and when implemented, degradation caused by leaching of calcium hydroxide is not significant. Therefore, leaching is not an aging mechanism that can lead to change in material properties for Containment concrete structural components.

Creep is significant when new concrete is subjected to load and decreases exponentially with time; and any degradation is noticeable in the first few years. In addition, creep proceeds at a decreasing rate with age, with 96% of creep occurring within 30 years. The concrete for the Containments was designed to ACI requirements that minimize the effects of creep. There has been no evidence of significant creep at St. Lucie Nuclear Plant. Therefore, concrete creep is not an aging mechanism that can lead to change in material properties for Containment concrete structural components.

As discussed previously, Containment concrete structural components are not exposed to elevated temperatures that exceed ACI threshold limits and, therefore, elevated temperature is not an aging mechanism that can lead to change in material properties for Containment concrete structural components.

Irradiation embrittlement was evaluated as an aging mechanism that could lead to change in material properties. Shielding from the water in the reactor core and the reactor vessel reduces the neutron flux, resulting in levels of accumulated exposure that are below the levels necessary to cause concrete degradation. The maximum gamma dose evaluated through the period of extended operation is below the dose required for concrete degradation. Therefore, irradiation embrittlement is not an aging mechanism that can lead to change in material properties for Containment concrete structural components.

Concrete structural components subject to loss of material due to aggressive chemical attack would also be subject to change in material properties due to the same aging mechanism.

Based on the above, change in material properties due to aggressive chemical attack is an aging effect requiring management for concrete structural components below groundwater elevation.

3.5.1.3.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Containment concrete structural components includes the following:

- NRC Bulletin 80-11, "Masonry Wall Design"
- NRC Information Notice 97-11, "Cement Erosion from Containment Subfoundations at Nuclear Power Plants"
- NRC Information Notice 98-26, "Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundations"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"
- NUREG/CP-0100, Prasad, N., et al., "Concrete Degradation Monitoring and Evaluation," Proceedings of the International Nuclear Power Plant Aging Symposium, August 30 - September 1, 1998
- NUREG/CR-4652, "Concrete Component Aging and its Significance Relative to Life Extension of Nuclear Power Plants"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.1.3.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Containment concrete structural component aging, in addition to interviews with responsible engineering personnel. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.1.3.2.

3.5.1.3.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.1.3.2. Table 3.5-2 contains the results of the aging management review for the Containments and summarizes the aging effects requiring management for Containment concrete structural components.

The aging effects requiring management are adequately managed by the following program:

St. Lucie plant-specific program:

- Systems and Structures Monitoring Program

Based on the evaluation provided in Appendix B for the program above, aging effects are adequately managed so that the intended functions of the Containment concrete structural components listed in Table 3.5-2 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.1.4 CONTAINMENT MISCELLANEOUS STRUCTURAL COMPONENTS

Containment miscellaneous structural components include:

- containment vessel moisture barriers
- containment hatch seals and gaskets
- door seals and gaskets
- fuel transfer tube penetration flexible membranes (in each annulus between the Containment vessels and the Reactor Containment Shield Buildings)
- sliding supports (Lubrite)

3.5.1.4.1 MATERIALS AND ENVIRONMENT

The Containment miscellaneous structural components consist of silicone, elastomers, and lubrite plates.

The Containment miscellaneous structural components are exposed to environments of containment air, indoor - not air conditioned, and outdoor (see Table 3.0-2). The specific materials and environments for Containment miscellaneous structural components are contained in Table 3.5-2. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.1.4.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for Containment miscellaneous structural components are loss of material and loss of seal. Each is discussed below.

<u>LOSS OF MATERIAL</u>

The only Containment miscellaneous structural components potentially subject to loss of material are the lubrite sliding plates. Aging mechanisms that can lead to loss of material for the lubrite sliding plates are wear and environmental degradation.

Lubrite plates were evaluated for loss of material due to wear and environmental degradation and determined not to require aging management. Lubrite products are solid, permanent, self-lubricating, and require no maintenance for the life of the product.

Accordingly, loss of material for Containment miscellaneous structural components is not an aging effect requiring management.

LOSS OF SEAL

The aging mechanisms that can lead to loss of seal are wear and environmental degradation.

The containment vessel moisture barriers were evaluated for loss of seal due to environmental degradation and determined to require aging management. The containment hatch seals and gaskets and door seals and gaskets were evaluated for loss of seal due to wear and determined to require aging management. The fuel transfer tube penetration flexible membrane was evaluated for loss of seal due to environmental degradation and determined not to require aging management. The flexible membrane is made from radiation resistant silicone rubber that will not age significantly enough to cause a loss of intended function.

Based on the above, loss of seal is an aging effect requiring management for selected Containment miscellaneous structural components.

3.5.1.4.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to Containment miscellaneous structural components includes the following:

- NRC Information Notice 88-61, "Control Room Habitability - Recent Reviews of OPE Rating Experience"
- NRC Information Notice 97-10, "Liner Plate Corrosion in Concrete Containments"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.1.4.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of Containment miscellaneous structural component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.1.4.2.

3.5.1.4.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.1.4.2. Table 3.5-2 contains the results of the aging management review for the Containments and summarizes the aging effects requiring management for Containment miscellaneous structural components.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding program in the GALL Report:

- ASME Section XI, Subsection IWE Inservice Inspection Program

St. Lucie plant-specific program:

- Periodic Surveillance and Preventive Maintenance Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions for the Containment miscellaneous structural components listed in Table 3.5-2 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.2 OTHER STRUCTURES

This aging management review identifies and evaluates aging effects on St. Lucie passive, long-lived structures and structural components (other than the Containments and selected structural components). Structures and structural components within the scope of license renewal and subject to aging management reviews are discussed in Section 2.4 and include:

- 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

Tables 3.5-3 through 3.5-16 contain the specific structural component and commodity groups, materials, intended functions, environments, aging effects, and aging management programs for each of the structures listed above. Structural components are grouped by material and environment for each structure. The structural component groups are:

- Steel in air
- Steel in fluid
- Concrete
- Miscellaneous

3.5.2.1 STEEL IN AIR STRUCTURAL COMPONENTS

Steel in air structural components include:

- framing, bracing, and connections
- stairs, ladders, platforms, checkered plate, and grating
- supports (component, piping, ducts, and tubing)
- non-safety related piping between class break and anchor
- pipe whip restraints

- cranes, hoists, and trolleys
- cable trays, conduits, and electrical enclosures
- cable tray, conduit, and electrical enclosure supports
- instrumentation supports
- instrument racks and frames
- doors and louvers

3.5.2.1.1 MATERIALS AND ENVIRONMENT

Steel in air structural components were designed and constructed in accordance with AISC standards. The codes and standards used for the design and fabrication are identified in Unit 1 UFSAR Section 3.8, and Unit 2 UFSAR Section 3.8. Steel in air structural components is constructed of coated or galvanized carbon steel, and stainless steel.

St. Lucie steel in air structural components are exposed to environments of outdoor, indoor - not air conditioned, indoor - air conditioned, and potential borated water leaks (see Table 3.0-2). The specific materials and environments for steel in air structural components for each of the structures listed in Subsection 3.5.2 are contained in Tables 3.5-3 through 3.5-16. For corresponding component/commodity groups included in the GALL Report [Reference 3.5-1], there are no differences in environment.

Pipe segments beyond the safety-related/non-safety related boundaries are constructed of carbon and stainless steel and consist of piping and inline components. The external surfaces of these pipe segments are exposed to the Indoor - not air conditioned and outdoor environments and potential borated water leaks. Internal environments of the pipe segments are the same as the internal environments for the systems in which the piping segments are installed.

3.5.2.1.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of the intended function(s) of steel in air structural components are loss of material, cracking, and change in material properties. Each is discussed below.

LOSS OF MATERIAL

Aging mechanisms that can lead to loss of material are mechanical wear, corrosion, and aggressive chemical attack. This may be seen as material staining, corrosion product buildup, and pitting. Loss of material may be uniform or localized.

Mechanical wear is associated with close-fitting mechanical components having relative motion and is not applicable to structural steel. Accordingly, mechanical wear is not an aging mechanism that can lead to loss of material in steel in air structural components.

Loss of material in steel may be caused by corrosion. Carbon steel in an air environment is susceptible to corrosion except under the following conditions: steel located in an air conditioned environment, or steel which is galvanized and not wetted. Stainless steel structural components are not subject to corrosion in the air environments at St. Lucie

Nuclear Plant. Accordingly, with the exceptions above, corrosion is an aging mechanism that can lead to loss of material in selected steel in air structural components.

Aggressive chemical attack due to boric acid is an aging mechanism for steel in air structural components. This form of corrosion is typically localized and is a result of leakage from borated water systems that can concentrate boric acid and lead to significant material loss of carbon steel components. Although this type of corrosion is event driven (boric acid leaks), boric acid corrosion was evaluated as an aging mechanism at St. Lucie.

Based on the above, loss of material due to corrosion and aggressive chemical attack is an aging effect requiring management for selected steel in air structural components.

CRACKING

Aging mechanisms that can lead to cracking of steel in air structural components are SCC and fatigue.

SCC is an age-related degradation mechanism that affects stainless steels but becomes significant only if tensile stresses and a corrosive environment exist. The stresses may be either applied (external) or residual (internal). The stress corrosion cracks themselves may be either transgranular or intergranular, depending upon the metal and the corrosive agent. As is normal in all cracking, the cracks are perpendicular to the tensile stress. Usually there is little or no obvious visual evidence of corrosion. In order for SCC to occur an unfavorable environment, such as wetted surfaces must be present. Since the only wetted surfaces are a result of event-driven incidents, such as boric acid leakage, SCC is not an aging mechanism that can lead to cracking for steel in air structural components.

Fatigue is a progressive degradation problem for materials subjected to cyclic application of loads that are less than the maximum allowable static loads. For steel components, fatigue is the cumulative effect of microstructural localized plastic deformation in the material section that results each time a stress cycle of sufficient magnitude occurs. Since the steel in air structural components are not subject to stress reversals due to cyclic loading, fatigue is not an aging mechanism that can lead to cracking in steel in air structural components.

Based on the above, cracking is not an aging effect requiring management for steel in air structural components.

CHANGE IN MATERIAL PROPERTIES

Aging mechanisms that can cause change in material properties are thermal and irradiation embrittlement, and creep and stress relaxation. Steel in air structural components outside the Containment are not exposed to the elevated temperatures or fluences that would cause embrittlement. Per Appendix C, creep and stress relaxation are not aging mechanisms that can lead to change in material properties at St. Lucie Units 1 and 2. Accordingly, change in material properties is not an aging effect requiring management for steel in air structural components.

3.5.2.1.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to steel in air structural components includes the following:

- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Information Notice 89-07, "Failures of Small-Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Render Emergency Diesels Inoperable"
- NRC Information Notice 89-80, "Potential For Water Hammer, Thermal Stratification, and Steam Binding in High Pressure Coolant Injection Piping"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.2.1.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of steel in air structural component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.2.1.2.

3.5.2.1.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.2.1.2. Tables 3.5-3 through 3.5-16 contain the results of the aging management review for the other structures and summarize the aging effects requiring management for steel in air structural components.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program

St. Lucie plant-specific programs:

- Systems and Structures Monitoring Program
- Periodic Surveillance and Preventive Maintenance Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the steel in air structural components listed in Tables 3.5-3 through 3.5-16 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.2.2 STEEL IN FLUID STRUCTURAL COMPONENTS

This subsection includes steel structural components that are exposed to fluids and those steel structural components that are exposed to both fluids and air. Steel structural components that are exposed to only an air environment were discussed in Subsection 3.5.2.1 above. Steel in fluid structural components include:

- spent fuel storage racks (including Boraflex)
- fuel transfer tubes and expansion bellows
- spent fuel pool liner plates
- fuel handling tools
- upenders
- fuel pool gates
- sheet piling

3.5.2.2.1 MATERIALS AND ENVIRONMENT

Steel in fluid structural components were designed and constructed in accordance with AISC standards. The codes and standards used for the design and fabrication of the steel in fluid structural components are in Unit 1 UFSAR Section 3.8, and Unit 2 UFSAR Section 3.8.

Steel in fluid structural components are constructed of carbon steel or stainless steel. In addition, the Unit 1 spent fuel storage racks contain Boraflex panels.

St. Lucie Units 1 and 2 steel in fluid structural components are exposed to a fluid environment of treated water - borated and air environments of indoor - not air conditioned, outdoor, buried, and embedded/encased in concrete (see Tables 3.0-1 and 3.0-2). The specific materials and environments for steel in fluid structural components for each structure listed in Subsection 3.5.2 are contained in Tables 3.5-3 through 3.5-16. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.2.2.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for steel in fluid structural components are loss of material, cracking, and change in material properties. The aging mechanisms that could lead to these aging effects in steel in fluid structural components were evaluated using the methodology provided in Appendix C. The results are provided below.

LOSS OF MATERIAL

The aging mechanism that can lead to loss of material for steel in fluid structural components is corrosion.

Corrosion of carbon steel in fluid structural components exposed to raw water is prevented by an impressed current cathodic protection system. Since sheet piling is not exposed to flowing water, erosion-corrosion is an not aging mechanism that can lead to loss of material for steel in fluid structural components exposed to raw water.

Based on the evaluation using the methodology described in Appendix C, corrosion (general, galvanic, crevice, erosion-corrosion, and microbiologically influenced corrosion) is not an aging mechanism that can lead to loss of material in steel in fluid structural components exposed to treated water - borated. Loss of material due to pitting corrosion for stainless steel in fluid structural components exposed to treated water - borated is an aging effect requiring management.

Based on the above, loss of material due to corrosion is an aging effect requiring management for selected steel in fluid structural components.

CRACKING

Aging mechanisms that can lead to cracking of steel in fluid structural components are SCC and fatigue.

Based on the evaluation using the methodology described in Appendix C, SCC and fatigue were evaluated for steel in fluid structural components at St. Lucie and determined not to lead to cracking requiring management. Accordingly, cracking is not an aging effect requiring management for steel in fluid structural components.

CHANGE IN MATERIAL PROPERTIES

Aging mechanisms that can cause change in material properties are irradiation and thermal embrittlement and Boraflex degradation (i.e., shrinkage, dissolution, and gap formation).

Steel in fluid structural components outside the Containments are not exposed to the elevated temperatures or fluences that would cause embrittlement. Accordingly, change in material properties is not an aging effect requiring management for steel in fluid structural components.

Boraflex is a neutron absorber inserted between the Unit 1 fuel storage cells in high-density fuel storage racks. Irradiation results in degradation of the Boraflex.

Based on the above, change in material properties due to irradiation of fuel storage rack Boraflex is an aging effect requiring management.

3.5.2.2.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to steel in fluid structural components includes the following:

- NRC Bulletin 94-01, "Potential Fuel Pool Draindown Caused by Inadequate Maintenance Practices at Dresden Unit 1"
- NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"
- NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"
- NRC Generic Letter 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks"
- NRC Information Notice 87-43, "Gaps in Neutron-Absorbing Material in High Density Spent Fuel Storage Racks"
- NRC Information Notice 89-07, "Failures of Small-Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Render Emergency Diesels Inoperable"
- NRC Information Notice 89-80, "Potential For Water Hammer, Thermal Stratification, and Steam Binding in High Pressure Coolant Injection Piping"
- NRC Information Notice 93-70, "Degradation of Boraflex Neutron Absorber Coupons"
- NRC Information Notice 95-38, "Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.2.2.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of steel in fluid structural component aging, in addition to interviews with responsible engineering personnel. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.2.2.2.

3.5.2.2.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.2.2.2. Tables 3.5-3 through 3.5-16 contain the results of the aging management review for the other structures and summarize the aging effects requiring management for steel in fluid structural components.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie programs consistent with the corresponding programs in the GALL Report:

- Boraflex Surveillance Program
- Chemistry Control Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions of the steel in fluid structural components listed in Tables 3.5-3 through 3.5-16 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.2.3 CONCRETE STRUCTURAL COMPONENTS

Concrete structural components include:

- foundations and columns
- walls, floors, and roofs
- equipment pads
- electric duct banks
- manholes
- trenches
- masonry block walls
- hatches
- retaining walls

Note: Reinforcing steel and embedded steel are evaluated with the concrete components.

3.5.2.3.1 MATERIALS AND ENVIRONMENT

Concrete structural components were designed and constructed in accordance with ACI and ASTM standards. The codes and standards used for the design and fabrication of the concrete structural components are identified in Unit 1 UFSAR Section 3.8 and Unit 2 UFSAR Section 3.8.

St. Lucie Units 1 and 2 concrete structural components are exposed to environments of outdoor, indoor - not air conditioned, indoor - air conditioned, buried, and raw water - salt water (see Table 3.0-2). The specific materials and environments for concrete structural components for each structure listed in Subsection 3.5.2 are contained in Tables 3.5-3 through 3.5-16. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.2.3.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for concrete structural components are loss of material, cracking, and change in material properties. Each is discussed below.

LOSS OF MATERIAL

Loss of material is manifested in concrete structural components as scaling, spalling, pitting, and erosion. Aging mechanisms that can lead to loss of material are freeze-thaw, abrasion and cavitation, elevated temperature, aggressive chemical attack, and corrosion of reinforcing and embedded/encased steel.

Freeze-thaw is considered an aging mechanism for concrete structural components that are exposed to severe weather conditions of numerous freeze-thaw cycles with significant amounts of winter rainfall. St. Lucie Nuclear Plant is located in a subtropical climate with long, warm summers accompanied by abundant rainfall and mild, dry winters with negligible freeze-thaw cycles. Therefore, freeze-thaw is not an aging mechanism that can lead to loss of material for concrete structural components.

Abrasion and cavitation is an aging mechanism that occurs only in concrete structures that are continually exposed to flowing water. The Intake Structures concrete components located below the intake canal water level are the only concrete components exposed to flowing water. The velocity of the intake water is significantly less than the threshold limits at which abrasion and cavitation degradation occurs. Therefore, abrasion and cavitation is not an aging mechanism that can lead to loss of material for concrete structural components.

Concrete structural components outside the Containments are not exposed to elevated temperatures that exceed ACI threshold limits and, therefore, elevated temperature is not an aging mechanism that can lead to loss of material for concrete structural components.

Aggressive chemical attack, leading to corrosion of reinforcing steel and embedded steel, was identified as an age-related degradation mechanism for concrete structural components. At St. Lucie Units 1 and 2, this is applicable to concrete structural components exposed to the groundwater, salt water flow, or salt water splash (Intake Cooling Water System discharge). The structures with concrete structural components located below groundwater elevation are the Intake Structures, the Intake, Discharge, and Emergency Cooling Canals, the Reactor Auxiliary Buildings, and the Steam Trestle Areas. The Intake Structures and the Intake, Discharge, and Emergency Cooling Canals concrete structural components are also exposed to high chlorides due to the flow of salt water.

Based on the above, loss of material due to aggressive chemical attack leading to corrosion of reinforcing and embedded steel is an aging effect that requires aging management for concrete structural components below groundwater elevation, exposed to salt water flow, or exposed to salt water splash.

CRACKING

Cracking is manifested in concrete structural components as complete or incomplete separation of the concrete into two or more parts. Aging mechanisms that can lead to cracking are freeze-thaw, reactions with aggregates, shrinkage, settlement, fatigue, and elevated temperature.

As discussed previously, freeze-thaw is not an aging mechanism that can lead to cracking for concrete structural components at St. Lucie Nuclear Plant.

St. Lucie Unit 1 and 2 concrete components were constructed using non-reactive aggregates whose acceptability was based on established industry standards and ASTM tests. Therefore, reaction with aggregates is not an aging mechanism that can lead to cracking for concrete structural components.

When concrete is exposed to air, large portions of the free water evaporate, causing shrinkage. At St. Lucie, low slump concrete was used, and adequate steel reinforcement was provided, which all minimize shrinkage. Based on industry information, 100% of concrete shrinkage occurs within 20 years. St. Lucie Unit 1 and 2 concrete structures and concrete structural components were constructed 18 to 25 years or more ago; therefore, concrete shrinkage is not an aging mechanism that can lead to cracking for concrete structural components.

Settlement is based directly on the physical properties of a structure's foundation material. The most pronounced settlement is evidenced in the first several months after construction. St. Lucie concrete structures are founded on compacted Class I fill consisting of clean sand and gravel with a maximum of 12% fines. After initial settlement occurred, the settlement ceased, no further significant settlement has occurred, and no further significant structural settlement is expected. Therefore, settlement is not an aging mechanism that can lead to cracking for concrete structural components.

Shrinkage and settlement of supporting structures can cause cracking of unreinforced masonry block walls. Cracking could reduce the structural strength of the walls. Any cracks that affected the structural integrity and could consequently impact the intended function(s) of the masonry block walls were identified in response to NRC Bulletin 80-11 and associated inspections.

Fatigue is a progressive degradation problem for materials subjected to cyclic application of loads that are less than the maximum allowable static loads. St. Lucie Unit 1 and 2 concrete structural components are designed in accordance with ACI standards and have good low-cycle fatigue properties. Although some concrete structural components are subject to high cycles of low-level repeated load, these components were designed in accordance with ACI standards, which limit the maximum design stress to less than 50% of the static stress of the concrete. Therefore, fatigue is not an aging mechanism that can lead to cracking for concrete structural components.

Concrete structural components outside the Containments are not exposed to elevated temperatures that exceed ACI threshold limits and, therefore, elevated temperature is not an aging mechanism that can lead to cracking for concrete structural components.

Based on the above, cracking due to shrinkage and settlement of unreinforced masonry block walls is an aging effect requiring management for concrete structural components.

CHANGE IN MATERIAL PROPERTIES

Change in material properties is manifested in concrete as increased permeability, increased porosity, reduction in pH, reduction in tensile strength, reduction in compressive strength, reduction in modulus of elasticity, and reduction in bond strength. Aging mechanisms that can lead to a change in material properties are leaching, creep, elevated temperature, irradiation embrittlement, and aggressive chemical attack.

Leaching of calcium hydroxide is observed on concrete that is alternately wetted and dried. White deposits that are left on the surface of the concrete are a solution of water, free lime from the concrete, and carbon dioxide that is readily seen on the surface of the concrete. St. Lucie Unit 1 and 2 concrete structures and concrete structural components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the guidance provided by the ACI, and when implemented, degradation caused by leaching of calcium hydroxide is not significant. Therefore, leaching is not an aging mechanism that can lead to change in material properties for concrete structural components.

Creep is significant when new concrete is subjected to load and decreases exponentially with time; and any degradation is noticeable in the first few years. In addition, creep proceeds at a decreasing rate with age, with 96% of creep occurring within 30 years. The concrete structural components were designed to ACI requirements that minimize the effects of creep. There has been no evidence of significant creep at St. Lucie. Therefore, concrete creep is not an aging mechanism that can lead to change in material properties for concrete structural components.

As discussed previously, concrete structural components are not exposed to elevated temperatures that exceed ACI threshold limits and, therefore, elevated temperature is not an aging mechanism that can lead to change in material properties for concrete structural components.

Irradiation embrittlement was evaluated as an aging mechanism that could lead to change in material properties. Neutron fluence levels and maximum integrated gamma doses were evaluated for the period of extended operation and determined to be below the threshold levels necessary to cause degradation of concrete. Therefore, irradiation embrittlement is not an aging mechanism that can lead to change in material properties for concrete structural components.

Concrete structural components subject to loss of material due to aggressive chemical attack would also be subject to change in material properties due to the same aging mechanism.

Based on the above, change in material properties due to aggressive chemical attack is an aging effect requiring management for concrete structural components below groundwater elevation, exposed to salt water flow, or exposed to salt water splash.

3.5.2.3.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to concrete structural components includes the following:

- NRC Bulletin 80-11, "Masonry Wall Design"
- NRC Information Notice 97-11, "Cement Erosion from Containment Subfoundations at Nuclear Power Plants"

- NRC Information Notice 85-25, "Consideration of Thermal Conditions in the Design and Installation of Supports for Diesel Generator Exhaust Silencers"
- NRC Information Notice 98-26, "Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundations"
- NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"
- NUREG/CP-0100, Prasad, N., et al., "Concrete Degradation Monitoring and Evaluation," Proceedings of the International Nuclear Power Plant Aging Symposium, August 30 - September 1, 1998
- NUREG/CR-4652, "Concrete Component Aging and its Significance Relative to Life Extension of Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.2.3.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of concrete structural component aging, in addition to interviews with responsible engineering personnel. No additional aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.2.3.2.

3.5.2.3.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.2.3.2. Tables 3.5-3 through 3.5-16 contain the results of the aging management review for the other structures and summarize the aging effects requiring management for concrete structural components.

The aging effects requiring management are adequately managed by the following program:

St. Lucie plant-specific program:

- Systems and Structures Monitoring Program

Based on the evaluation provided in Appendix B for the program above, aging effects are adequately managed so that the intended functions of the concrete structural components listed in Tables 3.5-3 through 3.5-16 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.2.4 MISCELLANEOUS STRUCTURAL COMPONENTS

Miscellaneous structural components include:

- fire rated assemblies (fire barriers, fire doors, penetration seals, etc.)
- door seals and gaskets
- non-metallic conduit

- earthen canal dikes
- weatherproofing (structures and sealants)

3.5.2.4.1 MATERIALS AND ENVIRONMENT

The miscellaneous structural components consist of a variety of materials, depending on their location and function. Materials used include, carbon steel, stainless steel, galvanized carbon steel, earth fill, polyvinyl chloride (PVC), silicone, elastomers, weatherproofing materials (caulking and sealants), and fire protection materials (marinite board, durablanket, silicone gel, Quelpyre, ethafoam, dymeric sealant, ceramic fiber, Thermo-Lag, and fire retardant coatings).

The miscellaneous structural components are exposed to different environments, depending on their location and function. Environments include outdoor, indoor - not air conditioned, indoor - air conditioned, containment air, and raw water - salt water (see Table 3.0-2). The specific materials and environments for miscellaneous structural components for each structure listed in Subsection 3.5.2 are contained in Tables 3.5-3 through 3.5-16. For corresponding component/commodity groups included in the GALL Report, there are no differences in environment.

3.5.2.4.2 AGING EFFECTS REQUIRING MANAGEMENT

The aging effects that could cause loss of intended function(s) for miscellaneous structural components are loss of material, loss of seal, and cracking. Each is discussed below.

<u>LOSS OF MATERIAL</u>

Aging mechanisms that can lead to loss of material for miscellaneous structural components are corrosion, wear, and environmental degradation.

Fire doors were evaluated for loss of material due to corrosion and determined to require aging management unless in an air conditioned environment. Fire barriers and earthen canal dikes were evaluated for loss of material due to environmental degradation. Fire barriers were determined not to age because they are exposed to benign indoor environments. Earthen canals were determined not to age because they are protected by concrete erosion protection.

Based on the above, loss of material due to general corrosion is an aging effect requiring management for select miscellaneous structural components.

<u>LOSS OF SEAL</u>

The aging mechanisms that can lead to loss of seal for miscellaneous structural components are wear and environmental degradation.

Door seals and gaskets were evaluated for loss of seal due to wear and determined to require aging management. Weatherproofing features were evaluated for loss of seal due to environmental degradation and determined to require aging management.

Based on the above, loss of seal is an aging effect requiring management for select miscellaneous structural components.

CRACKING

Aging mechanisms that can lead to cracking of miscellaneous structural components are shrinkage and environmental degradation.

Fire barrier penetration seals were evaluated for cracking due to shrinkage and determined not to require aging management since the seal material becomes a monolithic solid when cured that takes the form of the system to which each is injected or applied. In addition, SECY 96-146 "Technical Assessment of Fire Barrier Penetration Seals in Nuclear Power Plants" concludes that penetration seals are not subjected to aging effects.

Non-metallic conduits were evaluated for cracking due to environmental degradation and determined not to require aging management because they are not exposed to ultraviolet light.

Based on the above, cracking is an aging effect requiring management for miscellaneous structural components.

3.5.2.4.3 OPERATING EXPERIENCE

INDUSTRY EXPERIENCE

A review of industry operating history and a review of NRC generic communications were performed to validate the set of aging effects that require management. The industry correspondence that was reviewed for operating experience related to miscellaneous structural components includes the following:

- NRC Bulletin 92-01, "Failure Of Thermo-Lag 330 Fire Barrier System To Maintain Cabling In Wide Cable Trays And Small Conduits Free From Fire Damage"
- NRC Bulletin 92-01, Supplement 1, "Failure of Thermo-Lag 330 Fire Barrier System to Perform Its Specified Fire Endurance Function"
- NRC Generic Letter 92-08, "Thermo-Lag 330-1 Fire Barriers"
- NRC Information Notice 88-04, "Inadequate Qualification and Documentation of Fire Barrier Penetration Seals"
- NRC Information Notice 88-56, "Potential Problems with Silicone Foam Fire Barrier Penetration Seals"
- NRC Information Notice 88-61, "Control Room Habitability - Recent Reviews of OPE Rating Experience"
- NRC Information Notice 91-47, "Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test"
- NRC Information Notice 91-79, "Deficiencies in the Procedures for Installing Thermo-Lag Fire Barrier Materials"
- NRC Information Notice 91-79, Supplement 1, "Deficiencies Found in Thermo-Lag Fire Barrier Installation"

- NRC Information Notice 92-46, "Thermo-Lag Fire Barrier Material Special Review Team Final Report Findings, Current Fire Endurance Tests, And Ampacity"
- NRC Information Notice 92-55, "Current Fire Endurance Test Results For Thermo-Lag Fire Barrier Material"
- NRC Information Notice 92-82, "Results of Thermo-Lag 330-1 Combustibility Testing"
- NRC Information Notice 94-22, "Fire Endurance and Ampacity Derating Test Results for 3-hour Fire-Rated Thermo-Lag 330-1 Fire Barriers"
- NRC Information Notice 94-28, "Potential Problems With Fire-Barrier Penetration Seals"
- NRC Information Notice 94-34, "Thermo-Lag 330-660 Flexi-Blanket Ampacity Derating Concerns"
- NRC Information Notice 95-32, "Thermo-Lag 330-1 Flame Spread Test Results"
- NRC Information Notice 95-49 and Supplement 1, "Seismic Adequacy of Thermo-Lag Panels"
- NRC Information Notice 97-70, "Potential Problems with Fire Barrier Penetration Seals"
- NUREG-1552, "Fire Barrier Penetration Seals in Nuclear Power Plants"
- SECY-96-146, "Technical Assessment of Fire Barrier Penetration Seals in Nuclear Power Plants"

No aging effects requiring management were identified from the above documents beyond those already identified in Subsection 3.5.2.4.2.

PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was also reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of miscellaneous structural component aging, in addition to interviews with responsible engineering personnel. No aging effects requiring management were identified from this review beyond those identified in Subsection 3.5.2.4.2.

3.5.2.4.4 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.5.2.4.2. Tables 3.5-3 through 3.5-16 contain the results of the aging management review for the other structures and summarize the aging effects requiring management for miscellaneous structural components.

The aging effects requiring management are adequately managed by the following programs:

St. Lucie plant-specific programs:

- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

Based on the evaluations provided in Appendix B for the programs listed above, aging effects are adequately managed so that the intended functions for the miscellaneous structural components listed in Tables 3.5-3 through 3.5-16 are maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.5.3 REFERENCES

3.5-1 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U.S. Nuclear Regulatory Commission, April 2001.

3.5-2 FPL Letter to U. S. Nuclear Regulatory Commission, "Steam Generator and Reactor Coolant Pump Support Materials," L-77-349, November 18, 1977.

TABLE 3.5-1
STRUCTURAL COMPONENT INTENDED FUNCTIONS

1. Provide pressure boundary.
2. Provide structural support to safety-related components.
3. Provide shelter/protection to safety-related components (including radiation shielding).
4. Provide fire barriers to retard spreading of a fire.
5. Provide a source of cooling water for plant shutdown.
6. Provide missile barriers.
7. Provide structural support to non-safety related components whose failure could prevent satisfactory accomplishment of any of the required safety-related functions.
8. Provide flood protection barriers.
9. Provide boundary for safety-related ventilation.
10. Provide structural support and/or shelter to components required for FP, ATWS, and/or SBO events. (NOTE: Although not credited in the analyses for these events, these components have been conservatively included in the scope of license renewal.)
11. Provide pipe whip restraint and/or jet impingement protection.

TABLE 3.5-2
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Containment vessels [II A2.1-a]	1, 2, 7, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Containment vessels	1, 2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Structural steel framing (columns, beams, connections, etc.) [III A1.2-a, A4.2-a]	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Structural steel framing (columns, beams, connections, etc.)	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Stairs Ladders Platforms Handrails Checkered plate Grating	7	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-b]	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Reactor vessel supports [III B1.1.1-a]	2, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Reactor vessel supports [III B1.1.1-b]	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Pressurizer supports [III B1.1.1-a]	2, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Pressurizer supports [III B1.1.1-b]	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Reactor coolant pump supports [III B1.1.1-a]	2, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Reactor coolant pump supports [III B1.1.1-b]	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Steam generator supports [III B1.1.1-a]	2, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Steam generator supports [III B1.1.1-b]	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Airtight bulkhead doors (shield building)	3, 9	Carbon steel	Containment air Outdoor	Loss of material	Systems and Structures Monitoring Program
Maintenance hatch outside doors	3, 6, 9	Carbon steel Concrete	Containment air Outdoor	Loss of material	Systems and Structures Monitoring Program
Equipment and personnel hatches (maintenance hatches, personnel hatches, and escape hatches) including hinges, latches, and equalizing valves [II A3.2]	1, 4	Carbon steel	Containment air Indoor - not air conditioned Outdoor	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Equipment and personnel hatches (maintenance hatches, personnel hatches, and escape hatches) including hinges, latches, and equalizing valves	1, 4	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Piping and spare penetrations (includes bellows) [II A3.1]	1, 2, 4	Carbon steel	Containment air Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
		Stainless steel Nickel alloy	Indoor - not air conditioned Containment air	None	None required

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Piping and spare penetrations (includes bellows)	1, 2, 4	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Fuel transfer tube penetration sleeves [II A3.1-a, -b, -c]	1, 2, 4	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Fuel transfer tube penetration sleeves	1, 2, 4	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Reactor cavity seal rings	1	Stainless steel	Containment air	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Fuel transfer tubes and expansion bellows [II A3.1-b, -c, -d]	1, 2 , 4	Stainless steel	Containment air	None	None required
Fuel transfer tubes and expansion bellows	1, 2 , 4	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Refueling pool liner plates	1	Stainless steel	Containment air	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Fuel transfer flange supports	2	Stainless steel	Containment air	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Fuel transfer system (Unit 2 only)	2, 7	Stainless steel	Containment air	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program

**TABLE 3.5-2 (continued)
CONTAINMENTS**

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical penetrations [II A3.1-a]	1, 2, 4	Carbon steel	Containment air Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Electrical penetrations	1, 2, 4	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Heating and ventilation penetrations [II A3.1-a, -b, -c]	1, 2, 4	Carbon steel	Containment air Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Heating and ventilation penetrations	1, 2, 4	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Fuel transfer flanges for fuel transfer tube isolation	1, 4	Stainless steel	Containment air	None	None required
Polar cranes (passive components) [VII B.1.1, B.2.1]	7	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Telescoping jib cranes (passive components) [VII B.1.1]	7	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Telescoping jib cranes (passive components)	7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Other cranes and hoists (passive components)	7	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Refueling machines (passive components)	2, 7	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Conduits and cable trays	2, 3, 7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Containment air	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Conduit and cable tray supports [III B2.1-b]	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Conduit and cable tray supports	2, 7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Containment air	None	None required

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports [III B3.1-b]	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Containment air	None	None required
HVAC duct supports [III B2.1-a]	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
HVAC duct supports [III B2.1-b]	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC duct supports	2, 7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-b]	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-2 (continued) CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Trisodium phosphate (TSP) baskets (Unit 2 only)	2, 3	Stainless steel	Containment air	None	None required
Safety-related pipe supports and component supports [III B1.1.1-a, B1.2.1-a]	2, 10	Carbon steel	Containment air	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Safety-related pipe supports and component supports [III B1.1.1-b, B1.2.1-b]	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Containment air Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe supports [III B2.1-b]	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Containment air	None	None required
Pipe whip restraints [III B5.1-a]	11	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
Pipe whip restraints [III B5.1-b]	11	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Recirculation sump screens	2, 3	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Containment air	None	None required
Miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.)	2, 4, 6, 7, 10	Carbon steel	Containment air	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Containment air	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Reinforced concrete above groundwater (exterior walls and roofs)	2, 3, 4, 6, 7, 8, 9, 10	Concrete Carbon steel	Outdoor Containment air	None	None required
Reinforced concrete below groundwater (exterior walls and foundation) [III A1.1-e,-g]	2, 3, 7, 10	Concrete Carbon steel	Buried	Loss of material Change in material properties	Systems and Structures Monitoring Program
Reinforced concrete (interior shield walls, beams, slabs, missile shields, equipment pads, etc.)	2, 3, 6, 7, 10	Concrete Carbon steel	Containment air	None	None required
Reinforced concrete masonry block walls	2, 3	Concrete Carbon steel	Containment air	None	None required

TABLE 3.5-2 (continued)
CONTAINMENTS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Containment vessel moisture barriers [II A3.3-a]	3	Elastomer	Containment air Indoor - not air conditioned	Loss of seal	ASME Section XI, Subsection IWE Inservice Inspection Program
Reactor cavity seal ring seals	1	Elastomer	Containment air Treated water - borated	Loss of seal	Periodic Surveillance and Preventive Maintenance Program
Containment hatch seals and gaskets [II A3.3-a]	1	Elastomer	Containment air Indoor - not air conditioned	Loss of seal	ASME Section XI, Subsection IWE Inservice Inspection Program
Airtight bulkhead door seals [II A3.3-a]	9	Elastomer	Outdoor Indoor - not air conditioned	Loss of seal	Periodic Surveillance and Preventive Maintenance Program
Fuel transfer tube penetration flexible membranes (in annulus) [II A3.3-a]	9	Silicone	Containment air	None	None required
Lubrite sliding supports [III B1.1.3-a]	2, 10	Lubrite plate	Containment air	None	None required

TABLE 3.5-3
COMPONENT COOLING WATER AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Steel framing (columns, beams, and connections) [III A3.2-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Stairs Ladders Platforms Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program

TABLE 3.5-3 (continued)
COMPONENT COOLING WATER AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Missile barriers (Unit 1 only)	3, 6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Missile protection doors (Unit 2 only)	3, 6	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduits	2, 3, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Conduit supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-3 (continued)
COMPONENT COOLING WATER AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduit supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
HVAC duct supports [III B2.1-a]	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-3 (continued)
COMPONENT COOLING WATER AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Trolley hoists (passive components) [VII B.1.1]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater (external surfaces of foundation slab and walls below grating, walls and roofs above grating)	2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Buried Outdoor Indoor - not air conditioned	None	None required
Reinforced concrete (equipment pedestals and internal surfaces of walls and foundation slabs below grating) [III A3.1-d,-f]	2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Indoor - not air conditioned Outdoor	Loss of material[1] Change in material properties[1]	Systems and Structures Monitoring Program

NOTES 1. Plant experience shows a history of loss of material and change in material properties for these concrete components.

TABLE 3.5-4
CONDENSATE POLISHER BUILDING

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Component supports (non-safety related)	10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Pipe supports (non-safety related)	10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater	10	Concrete Carbon steel	Indoor - not air conditioned Outdoor	None	None required

TABLE 3.5-5
CONDENSATE STORAGE TANK ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Stairs Ladders Platforms Handrails Checkered plate Grating	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-5 (continued)
CONDENSATE STORAGE TANK ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduits	2, 3, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Conduit supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-5 (continued)
CONDENSATE STORAGE TANK ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Outdoor Indoor - not air conditioned	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-5 (continued)
CONDENSATE STORAGE TANK ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Missile protection hood (Unit 2 only)	6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater	2, 3, 4, 6, 7, 10	Concrete Carbon steel	Outdoor	None	None required

TABLE 3.5-6
DIESEL OIL EQUIPMENT ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Stairs Ladders Platforms Handrails Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-6 (continued)
DIESEL OIL EQUIPMENT ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduits	2, 3, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Conduit supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-6 (continued)
DIESEL OIL EQUIPMENT ENCLOSURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Miscellaneous steel (i.e., missile barrier doors) (Unit 2 only)	4, 6	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Diesel oil storage tanks foundations	2, 7, 10	Concrete Carbon steel	Outdoor Buried	None	None required
Reinforced concrete above groundwater	2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Outdoor	None	None required

TABLE 3.5-7
EMERGENCY DIESEL GENERATOR BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Stairs Ladders Platforms Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned	None	None required
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Conduits	2, 3, 7, 10	Carbon steel - galvanized Stainless steel	Indoor - not air conditioned	None	None required
Conduit supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Conduit supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned	None	None required

TABLE 3.5-7 (continued)
EMERGENCY DIESEL GENERATOR BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panels and enclosures	2, 7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
Tubing supports	2, 7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Miscellaneous steel	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Missile protection doors	6, 8	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Missile protection exhaust hoods (Unit 2 only)	3, 6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required

TABLE 3.5-7 (continued)
EMERGENCY DIESEL GENERATOR BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Exterior louvers (for ventilation and missile protection) (Unit 1 only)	3, 6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Trolley hoists (passive components) [VII B.1.1]	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater (slabs, walls, roofs, trenches)	2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Outdoor Indoor - not air conditioned	None	None required

TABLE 3.5-8[1, 2]
FIRE RATED ASSEMBLIES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fire Barriers					
Conduit caps	1[3], 4	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
Fire wrap (conduit and steel supports)	4	Thermo-lag 330-1	Indoor - air conditioned Indoor - not air conditioned Containment air	None	None required
Conduit plugs	4	Ceramic fiber Quelpyre mastic 703B Fire retardant coating	Indoor - air conditioned Indoor - not air conditioned	None	None required
Miscellaneous barriers	1[3], 4	Thermo-lag 330-1 (panels, wrap, spray, or troweled) Thermo-lag 770-1 (panels) Ceramic fiber/stainless steel sheet metal (panels)	Indoor - air conditioned Indoor - not air conditioned	None	None required

NOTES
1. Concrete and steel structural components that serve as fire barriers are addressed with each structure.
2. Hose stations are included in component/commodity groups "Hose station-fittings" and "Hose station - nozzles," and are evaluated with Fire Protection (Table 3.3-6) and Primary Makeup Water (Table 3.3-11). Hose racks are included in the component /commodity group "Component supports (non-safety related)."
3. Selected structural components in this group provide a pressure boundary for the Halon system for the Unit 1 cable spreading room.

TABLE 3.5-8 (continued)
FIRE RATED ASSEMBLIES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fire Barriers (continued)					
Fire doors (Appendix R barriers) [VII G.3.3, G.4.3]	1[1], 4	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned Outdoor	Loss of material	Fire Protection Program
Fire doors - airtight [VII G.3.3]	4, 9	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Fire Protection Program
Fire doors - watertight [VII G.3.3]	4, 8	Carbon steel	Indoor - not air conditioned	Loss of material	Fire Protection Program
Flame impingement shields	4	Insulating blankets (B&B or Mecatiss)	Containment air	None	None required
Radiant energy shields	4	Stainless steel	Containment air	None	None required
Fire sealed isolation joint [VII G.3.1]	4	Cerablanket Dymeric sealant Ethafoam Carbon steel plate	Indoor - not air conditioned	None	None required

NOTES 1. Selected structural components in this group provide a pressure boundary for the Halon system for the Unit 1 cable spreading room.

TABLE 3.5-8 (continued)
FIRE RATED ASSEMBLIES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Fire Seals					
Mechanical penetrations: (Type M-1, M-2, M-3, M-4, M-6, M-7, M-9) [VII G.3.1, G.4.1]	1[1], 4	Silicone Aluminum Carbon steel - galvanized Stainless steel Durablanket Ceramic fiber	Indoor - air conditioned Indoor - not air conditioned	None	None required
Cable tray penetrations [VII G.3.1]	1[1], 4	Marinite board Ceramic fiber Fire retardant coating.	Indoor - air conditioned Indoor - not air conditioned	None	None required

NOTES 1. Selected structural components in this group provide a pressure boundary for the Halon system for the Unit 1 cable spreading room.

TABLE 3.5-9
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Structural steel framing (columns, beams, connections, etc.)	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Stairs Ladders Platforms Handrails Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Safety-related pipe supports and component supports [III B1.2.1-a]	2	Carbon steel	Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Safety-related pipe supports and component supports	2	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe supports	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe segments between class break and seismic anchor	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required
Miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.)	6, 7	Carbon steel	Outdoor Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Airtight doors (Unit 2 only)	9	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduits	2, 3, 7	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required
Conduit supports [III B2.1-a]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Conduit supports	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Conduit supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panels and enclosures	2, 3, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panel and enclosure supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required
HVAC duct supports [III B2.1-a]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
HVAC duct supports	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC duct supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC louver (Unit 2 only)	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Tubing supports	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Tubing supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Fuel transfer tube penetration sleeve	3	Carbon steel	Embedded/encased	None	None required
			Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWE Inservice Inspection Program
Trolley hoists and cranes (passive components) [VII B.1.1]	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Spent fuel cask handling cranes (passive components) [VII B.1.1, B2.1]	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Spent fuel handling machines (passive components) [VII B.1.1]	2, 7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Fuel pool gates	1	Stainless steel	Indoor - not air conditioned	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Fuel transfer tubes and expansion bellows [II A3.1-d]	1	Stainless steel	Indoor - not air conditioned	None	None required
Fuel transfer tubes and expansion bellows	1	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Pool liner plates [III A5.2-b]	1	Stainless steel	Indoor - not air conditioned	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Fuel handling tools (Unit 2 only)	2, 7	Stainless steel	Indoor - not air conditioned	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Upender - passive components (Unit 2 only)	2, 7	Stainless steel	Indoor - not air conditioned	None	None required
			Treated water - borated	Loss of material	Chemistry Control Program
Spent fuel storage racks [VII A2.1.2]	2, 3	Stainless steel	Treated water - borated	Loss of material	Chemistry Control Program
Boraflex (Unit 1 only) [VII A2.1.1]	3	Boron impregnated polymer	Treated water - borated	Change in material properties	Boraflex Surveillance Program
Reinforced concrete above groundwater	2, 3, 6, 7, 8, 10	Concrete Carbon steel	Indoor - not air conditioned Outdoor	None	None required
Unreinforced concrete masonry block walls [III A5.3-a]	7	Concrete	Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program

TABLE 3.5-9 (continued)
FUEL HANDLING BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cask removal L-shape hatches	3, 6	Concrete Carbon steel	Indoor - not air conditioned Outdoor	None	None required
Airtight door seals	9	Elastomers	Indoor - not air conditioned Outdoor	Loss of seal	Periodic Surveillance and Preventive Maintenance Program
Weatherproofing	3	Caulking and sealants	Outdoor	Loss of seal	Systems and Structures Monitoring Program

TABLE 3.5-10
INTAKE, DISCHARGE, AND EMERGENCY COOLING CANALS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Concrete erosion protection (concrete paving and grout filled fabric between Intake Structures and Ultimate Heat Sink dam)	5, 10	Concrete Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Concrete erosion protection (concrete paving and grout filled fabric between Intake Structures and Ultimate Heat Sink dam) [III A6.1-d,-e]	5, 10	Concrete Carbon steel	Raw water - salt water	Loss of material	Systems and Structures Monitoring Program
				Change in material properties	Systems and Structures Monitoring Program
Earthen canal dikes [III A6.4-a]	5, 10	Earth fill	Raw water - salt water Outdoor	None	None required

TABLE 3.5-11
INTAKE STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	2, 6, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Structural steel framing (columns, beams, connections, etc.)	2, 6, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Miscellaneous steel (i.e., missile barriers, hatch frame covers, etc.)	2, 3, 6, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-11 (continued)
INTAKE STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduits	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Conduit supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-11 (continued)
INTAKE STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Cranes (passive components) [VII B1.1, B2.1]	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Cranes (passive components)	7	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete (slabs, walls, roofs) [III A6.1-d,-e]	2, 3, 5, 6, 7, 10	Concrete Carbon steel	Raw water - salt water	Loss of material Change in material properties	Systems and Structures Monitoring Program
Reinforced concrete (slabs, walls, roofs)	2, 3, 5, 6, 7, 10	Concrete Carbon steel	Outdoor	None	None required
Reinforced concrete (pump pedestals) [III A6.1-d,-e]	2	Concrete Carbon steel	Outdoor	Loss of material Change in material properties	Systems and Structures Monitoring Program
Retaining walls [III A6.1-d,-e]	2	Concrete Carbon steel	Raw water - salt water	Loss of material Change in material properties	Systems and Structures Monitoring Program
Conduits (non-metallic)	2, 3, 7, 10	PVC	Outdoor[1]	None	None required
Intake level recorders (PVC pipe)	7	PVC	Embedded	None	None required
Weatherproofing	3	Caulking and sealants	Outdoor	Loss of seal	Systems and Structures Monitoring Program

NOTES: 1. Located in pump missile enclosures and not exposed to direct sunlight.

TABLE 3.5-12
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	2, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Structural steel framing (columns, beams, connections, etc.)	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Stairs Ladders Platforms Handrails Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Indoor - not air conditioned	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Safety-related pipe supports and component supports	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe supports	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - not air conditioned	None	None required
Miscellaneous steel (i.e., radiation shielding, missile barriers, hatch frame covers, etc.)	2, 3, 4, 6, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Missile protection doors	6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Watertight doors	8, 9	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Airtight doors	7, 9	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Conduits and cable trays	2, 3, 7, 10	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - air conditioned Indoor - not air conditioned	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Conduit and cable tray supports	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduit and cable tray supports	2, 7, 10	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Indoor - air conditioned Indoor - not air conditioned	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC duct supports [III B2.1-a]	2, 7	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
HVAC duct supports	2, 7	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC duct supports	2, 7	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Indoor - air conditioned	None	None required
			Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Tubing supports	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Indoor - air conditioned Indoor - not air conditioned	None	None required
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
HVAC louvers	3, 7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Pipe whip restraints [III B5.1-a]	11	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Pipe whip restraints	11	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Trolleys and hoists (passive components) [VII B1.1]	7	Carbon steel	Indoor - not air conditioned	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater	1[1], 2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Outdoor Indoor - not air conditioned Indoor - air conditioned	None	None required

NOTES 1. Selected structural components in this group provide a pressure boundary for the Halon system for the Unit 1 cable spreading room.

TABLE 3.5-12 (continued)
REACTOR AUXILIARY BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reinforced concrete below groundwater (exterior) [III A3.1-e,-g]	2, 3, 7, 10	Concrete Carbon steel	Buried	Loss of material Change in material properties	Systems and Structures Monitoring Program
Reinforced concrete below groundwater (interior)	2, 3, 4, 6, 7, 8, 10	Concrete Carbon steel	Indoor - not air conditioned	None	None required
Reinforced concrete masonry block walls	1[1], 2, 3, 4, 7, 10	Concrete Carbon steel	Indoor - air conditioned Indoor - not air conditioned	None	None required
Unreinforced concrete masonry block walls [III A3.3-a]	4, 7	Concrete	Indoor - air conditioned Indoor - not air conditioned	Cracking	Systems and Structures Monitoring Program
Airtight door seals	9	Elastomers	Indoor - air conditioned Indoor - not air conditioned Outdoor	Loss of seal	Periodic Surveillance and Preventive Maintenance Program
Watertight door seals	8, 9	Elastomers	Indoor - air conditioned Indoor - not air conditioned Outdoor	Loss of seal	Periodic Surveillance and Preventive Maintenance Program
Weatherproofing	3	Caulking and sealants	Outdoor	Loss of seal	Systems and Structures Monitoring Program

NOTES 1. Selected structural components in this group provide a pressure boundary for the Halon system for the Unit 1 cable spreading room.

TABLE 3.5-13
STEAM TRESTLE AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	2, 6, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Stairs Ladders Platforms Handrails Checkered plate	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (Non-safety related)	7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-13 (continued)
STEAM TRESTLE AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Non-safety related pipe segments between class break and seismic anchor	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Miscellaneous steel (i.e., missile barriers, steel grating, etc.)	3, 4, 6, 7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Conduits and cable trays	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit and cable tray supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required

TABLE 3.5-13 (continued)
STEAM TRESTLE AREAS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater	2, 3, 4, 7, 10	Concrete Carbon steel	Outdoor Buried	None	None required
Reinforced concrete below groundwater (exterior) [III A3.1-e,-g]	2, 7, 10	Concrete Carbon steel	Buried	Loss of material Change in material properties	Systems and Structures Monitoring Program
Pipe whip restraints	11	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-14
TURBINE BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Structural steel framing (columns, beams, connections, etc.) [III A3.2-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe segments between the class break and the seismic anchor	2, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe supports (including the pipe hangers that indirectly support the Unit 1 safety-related main feedwater isolation valve motors) [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduits and cable trays	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-14 (continued)
TURBINE BUILDINGS

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduit and cable tray supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Gantry cranes (passive components) [VII B1.1, B2.1]	7	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Turbine generator casings (covers)	6	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Reinforced concrete above groundwater	7, 10	Concrete Carbon steel	Outdoor Buried	None	None required

TABLE 3.5-15
ULTIMATE HEAT SINK DAM

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Stairs Ladders Platforms Handrails Checkered plate Grating	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related) [III B2.1-a]	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Non-safety related pipe supports [III B2.1-a]	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-15 (continued)
ULTIMATE HEAT SINK DAM

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Non-safety related pipe segments between class break and seismic anchor	2, 7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Miscellaneous steel (i.e., missile barriers, hatch covers, etc.)	3, 6	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduits and cable trays	2, 3, 7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit and cable tray supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-15 (continued)
ULTIMATE HEAT SINK DAM

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panels and enclosures	2, 3, 7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Indoor - not air conditioned Outdoor	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Electrical and instrument panel and enclosure supports	2, 7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Tubing supports [III B2.1-a]	7	Carbon steel	Indoor - not air conditioned Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	7	Carbon steel - galvanized	Indoor - not air conditioned Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
Steel sheet piling (beneath dam) [III A6.2-a]	3	Carbon steel	Buried	None	None required

TABLE 3.5-15 (continued)
ULTIMATE HEAT SINK DAM

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Reinforced concrete (walls, slabs, roofs) [III A6.1-b,-d,-e]	2, 3, 6	Concrete Carbon steel	Raw water - salt water	Loss of material Change in material properties	Systems and Structures Monitoring Program

TABLE 3.5-16
YARD STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Component supports (non-safety related) [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Component supports (non-safety related)	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Component supports (non-safety related)	7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Safety-related pipe supports and component supports [III B1.2.1-a]	2, 10	Carbon steel	Outdoor	Loss of material	ASME Section XI, Subsection IWF Inservice Inspection Program
Safety-related pipe supports and component supports	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe supports [III B2.1-a]	7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Non-safety related pipe supports	7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Non-safety related pipe segments between class break and seismic anchor	2, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
		Stainless steel	Outdoor	None	None required

TABLE 3.5-16 (continued)
YARD STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Conduits and cable trays	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Outdoor	None	None required
Conduit and cable tray supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Conduit and cable tray supports	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Conduit and cable tray supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panels and enclosures	2, 3, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
		Stainless steel	Outdoor	None	None required
Electrical and instrument panel and enclosure supports [III B3.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program

TABLE 3.5-16 (continued)
YARD STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Electrical and instrument panel and enclosure supports	2, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Electrical and instrument panel and enclosure supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports [III B2.1-a]	2, 7, 10	Carbon steel	Outdoor	Loss of material	Systems and Structures Monitoring Program
Tubing supports	2, 7, 10	Carbon steel	Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Tubing supports	2, 7, 10	Carbon steel - galvanized	Outdoor	None	None required
			Outdoor (wetted)	Loss of material	Systems and Structures Monitoring Program
			Borated water leaks	Loss of material	Boric Acid Wastage Surveillance Program
Steel missile shield for diesel oil pipe (Unit 2 only)	6	Carbon steel	Buried	Loss of material	Systems and Structures Monitoring Program
Discharge canal nose wave protection (sheet piling) [III A6.2-a]	8	Carbon steel	Buried Embedded/encased	None	None required

TABLE 3.5-16 (continued)
YARD STRUCTURES

Component/ Commodity Group [GALL Reference]	Intended Function (See Table 3.5-1)	Material	Environment	Aging Effects Requiring Management	Program/Activity
Foundations (fire pumps, pipe supports, city water tanks, refueling water tanks, and Unit 2 primary water tank)	2, 10	Concrete Carbon steel	Outdoor	None	None required
Concrete missile shield for diesel oil pipe	6	Concrete Carbon steel	Buried	None	None required
Discharge canal nose wave protection (concrete cap)	8	Concrete Carbon steel	Outdoor	None	None required
Electrical duct banks and manholes	2, 3, 7, 10	Concrete Carbon steel	Buried	None	None required
Reinforced concrete pipe trenches	2, 3, 7, 10	Concrete Carbon steel	Buried	None	None required

3.6 ELECTRICAL AND INSTRUMENTATION AND CONTROLS

Section 2.5 provides a description of the electrical/I&C components requiring aging management review for license renewal. This section provides the results of the aging management review of the electrical/I&C components. The results of this section are also summarized in Table 3.6-5.

As stated in Section 2.5, the only electrical/I&C component commodity group subject to an aging management review is Cables and Connections (including insulated cables and connections, uninsulated ground conductors, splices, and terminal blocks) not included in the Environmental Qualification Program.

3.6.1 AGING EFFECTS REQUIRING MANAGEMENT

3.6.1.1 NON-ENVIRONMENTALLY QUALIFIED INSULATED CABLES AND CONNECTIONS

An evaluation published by the U. S. Department of Energy (DOE), "Aging Management Guideline (AMG) for Commercial Nuclear Power Plants - Electrical Cable and Terminations" [Reference 3.6-1, (DOE Cable AMG)], provides a comprehensive compilation and evaluation of information on the topics of insulated cables and connections, spliced connections, and terminal blocks. The electrical/I&C non-metallic materials are evaluated with the cable and connector materials in this evaluation. The DOE Cable AMG evaluated the stressors acting on cable and connection components, industry data on aging and failure of these components, and the maintenance activities performed on cable systems. Also evaluated were the main subsystems within cables, including the conductors, insulation, shielding, tape wraps, and jacketing, as well as all subcomponents associated with each type of connection.

The principal aging mechanisms and anticipated effects resulting from environmental and operating stresses were identified, evaluated, and correlated with plant experience to determine whether the predicted effects are consistent with field experience. As such, the information, evaluations, and conclusions contained in the DOE Cable AMG are used for the evaluation of aging effects in this subsection.

The most significant and observed aging mechanisms for insulated cables and connections are listed in the DOE Cable AMG, Table 4-18. The aging mechanisms from that table are used in this subsection as the starting point for identifying aging effects for insulated cables and connections. The potential aging effects along with the applicable stressors that are evaluated for insulated cables and connections are presented in Table 3.6-1 and are discussed in the following subsections.

3.6.1.1.1 LOW-VOLTAGE METAL CONNECTOR CONTACT SURFACES — MOISTURE AND OXYGEN

The DOE Cable AMG, Section 3.7.2.1.3, states that 3% 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 AMG, moisture intrusion accounted for only 10 failures in all of the operating plants in the United States.

St. Lucie Units 1 and 2 structures where electrical/I&C components may be exposed to moisture are indicated in Table 3.6-2. From the potential moisture sources identified in Table 3.6-2, precipitation and potential boric acid leaks require consideration for low-voltage connectors. All low-voltage metal connectors are located in enclosures or protected from the environment with qualified splices. Thus, aging effects related to moisture and oxygen, and boric acid leakage do not require management for low-voltage connectors at St. Lucie.

Note: Electrical enclosures are treated as structural components and are discussed with each structure, as applicable, in Section 3.5.

3.6.1.1.2 LOW-VOLTAGE METAL COMPRESSION FITTINGS — VIBRATION AND TENSILE STRESS

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 Units 1 and 2 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 [Reference 3.6-2], which states, "Based on the above evaluation, the staff concludes that the issue of degradation induced by human activities need not be considered as a separate aging effect and should be excluded from an aging management review."
- 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 deficiencies in the cables. Any evidence of cable abnormalities would result in the condition being addressed under the corrective action program.

3.6.1.1.3 MEDIUM-VOLTAGE INSULATION (CABLE AND CONNECTIONS) — MOISTURE AND VOLTAGE STRESS

The DOE Cable AMG, Section 3.7.4, describes a survey of 25 fossil and nuclear power plants that was conducted to determine the number and types of medium-voltage cable failures that have occurred. The survey identified only 27 failures in almost 1000 plant-years of experience. The failures that occurred, other than moisture-produced water trees, were related to wetting in conjunction with manufacturing defects or damaged terminations due to improper installation, and were not related to aging effects.

St. Lucie structures where electrical/I&C cable and components may be exposed to moisture are indicated in Table 3.6-2. From the potential moisture sources identified in

Table 3.6-2, precipitation and standing water in duct banks require further consideration 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 AMG. 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 15kV. Water treeing is a long-term degradation and failure phenomenon that is documented 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.

St. Lucie Units 1 and 2 medium-voltage applications, defined as 2kV to 15kV, use lead sheath cable to prevent the effects of moisture on the cables. The FPL 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 "…EPR/lead sheath cable is designed for applications in which liquid contamination is present and reliability is paramount. The sheath combined with the overall jacket provides a virtually impenetrable barrier against hostile environments - 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. Therefore, aging effects related to cable exposed to moisture and voltage stress do not require management at St. Lucie.

3.6.1.1.4 MEDIUM- AND LOW-VOLTAGE INSULATION (CABLE AND CONNECTIONS) - RADIATION AND OXYGEN

The DOE Cable AMG, 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 Units 1 and 2 evaluations use the moderate damage dose from the DOE Cable AMG as the limiting radiation value shown in Table 3.6-3, unless otherwise noted in the table.

The maximum operating dose shown in Table 3.6-3 includes the maximum 60-year normal exposure inside Containment. This is conservative, especially for cables located outside Containment.

A comparison of the maximum operating dose and the moderate damage doses in Table 3.6-3 shows that all of the insulation materials included in this aging management review will not exceed the moderate damage doses. Therefore, aging effects caused by radiation exposure will not adversely affect the intended function of insulated cables and connections and electrical/I&C penetrations during the extended period of operation. Therefore, aging effects related to radiation do not require management for cables and connections and electrical/I&C penetrations included in the aging management review.

3.6.1.1.5 MEDIUM- AND LOW-VOLTAGE INSULATION (CABLE AND CONNECTIONS) - HEAT AND OXYGEN

A maximum operating temperature was developed for each insulation type based on cable applications at St. Lucie Units 1 and 2. The maximum operating temperature indicated in Table 3.6-4 incorporates a conservative value for self-heating for power applications combined with the maximum design ambient temperature.

The Arrhenius method, as described in EPRI NP-1558, "A Review of Equipment Aging Theory and Technology" [Reference 3.6-3], was used 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.

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 materials used in low- and medium-voltage power cables and connections can withstand the maximum operating temperatures for at least 60 years.

<u>HYPALON, EPR, AND EPDM CABLE INSULATION</u>

The maximum cable temperature, including self-heating, for Hypalon, EPR, and EPDM is 162.0°F. The calculated maximum temperature for a 60-year life is 154.0°F for Hypalon and 154.9°F for EPR and EPDM. Thus, the difference between the maximum cable temperature and the maximum temperature for a 60-year life is 8.0°F for Hypalon and 7.1°F for EPR and EPDM. This difference is very small and is considered to be within the conservatisms incorporated in the maximum cable temperature and the maximum 60-year continuous use temperatures, as discussed below.

Research funded by the NRC and published in NUREG/CR-6384, "Literature Review of Environmental Qualification of Safety-Related Electric Cables" [Reference 3.6-4], determined that the retention-of-elongation of most cable insulation materials can be reduced to 0% and the insulation will still be capable of withstanding a postulated LOCA and remain functional.

The maximum temperature for 60-year life listed in Table 3.6-4 is based on a 50% retention-of-elongation for Hypalon, a 40% retention-of-elongation for EPR, and a 40% loss-of-elongation for EPDM. Since the cables and connections subject to an aging management review 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% retention-of-elongation is 167.0°F, which is greater than the maximum cable temperature of 162.0°F. The EPR and EPDM maximum temperatures for 60 year life using 15% retention-of-elongation are 167.0°F and 189°F, respectively, which are also greater than the 162.0°F maximum cable temperature.

Given these conservatisms, there is reasonable assurance that Hypalon, EPR, and EPDM insulated cables will not thermally age through the extended period of operation to the point that they will not be able to perform their intended function.

3.6.1.1.6 MEDIUM- AND LOW-VOLTAGE INSULATION (CABLE AND CONNECTIONS) — ADVERSE LOCALIZED ENVIRONMENTS

An extensive review of St. Lucie Nuclear Plant operating experience associated with cables and connections (connectors, splices, and terminal blocks) was performed, 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, walkdowns of accessible non-EQ cables and connections within the scope of license renewal found no adverse localized environments caused by heat or radiation.

The potential sources of adverse localized heat environments at St. Lucie Units 1 and 2 are from high temperature Reactor Coolant, Main Steam, Feedwater and Blowdown System piping and components. Most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environments because of the following:

1. The Intake Structures, Steam Trestle Areas, Component Cooling Water Area - Unit 1, Condensate Storage Tank Enclosure - Unit 1, Ultimate Heat Sink Dam, and Yard Structures are outdoor areas where cable and connections are not subject to adverse localized temperature and radiation effects.
2. The Turbine Buildings are outdoor areas with no external walls or roofs.
3. The Reactor Auxiliary Buildings, Component Cooling Water Area - Unit 2, Condensate Storage Tank Enclosure - Unit 2, 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 Reactor Auxiliary Buildings contain Steam Generator Blowdown System piping and components in limited areas.
4. With regard to radiation, the only buildings with any appreciable radiation levels are the Containments, the Reactor Auxiliary Buildings, and the Fuel Handling Buildings. However, non-EQ cables and connections in the Reactor Auxiliary Buildings 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% failed fuel (see further discussion below).

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 the 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.

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 describe the Area Radiation Monitoring Systems. 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 Containments are the same as cable and connection insulation materials already included in the Environmental Qualification Program at St. Lucie. The Area Radiation Monitoring Systems have 59 monitors (26 in Unit 1 and 33 in Unit 2) located throughout the Reactor Auxiliary Buildings 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 walkdowns and periodic Health Physics radiation monitoring (surveys of areas in the Reactor Auxiliary Buildings and Fuel Handling Buildings 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% failed fuel. This is conservative because St. Lucie Units 1 and 2 have never operated with more than 0.1% 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 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% to 60% 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% and the insulation will still be capable of withstanding a LOCA and remain functional. As the insulated cables and connections subject to an aging management review will either not be subjected to an accident environment or are not required to function after being subjected to an accident environment, the endpoints chosen for this review are 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%, 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 March 19, 1999. As added indication that there is margin in the thermal aging, preliminary conclusions from LOCA tests 1, 2, and 3 of the NRC research program indicate that, "Electric cables with insulation EAB (elongation-at-break) values as low as 5% performed acceptably 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.

Table 3.6-3 shows that the radiation values that non-EQ cable and connection insulation materials can withstand are much greater than actual design values for the 60-year life of the plant.

Based on the original St. Lucie Units 1 and 2 cable routing designs, plant-specific operating experience, and periodic 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

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.

Review of available industry 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 ground systems due to aging effects. Therefore, based on industry and plant-specific experiences, no aging effects requiring management were identified for the plant grounding system.

3.6.2 OPERATING EXPERIENCE

3.6.2.1 INDUSTRY EXPERIENCE

The DOE Cable AMG review includes an industry-wide operating experience review of failures and aging effects of electrical cables and terminations. No aging effects were identified from the DOE Cable AMG beyond those already identified in Subsection 3.6.1.

An incident occurred at the Davis-Besse Nuclear Generating Station, October 2, 1999. A component cooling water pump tripped as a result of a phase-to-ground fault on a medium-voltage 3-phase power cable. The cable was installed in a 4-inch PVC conduit, which runs partially underground, and had been in service for about 23 years.

As noted above, all medium-voltage applications (2kV to 15kV) at St. Lucie Nuclear Plant use lead sheath cable to prevent the effects of moisture on the cables. Based on St. Lucie's medium-voltage cable design, this incident is not applicable to medium-voltage cables at St. Lucie Units 1 and 2.

3.6.2.2 PLANT-SPECIFIC EXPERIENCE

St. Lucie Units 1 and 2 operating experience was reviewed to validate the identified aging effects requiring management. This review included a survey of St. Lucie non-conformance reports, licensee event reports, and condition reports for any documented instances of electrical/I&C component aging, in addition to interviews with responsible engineering personnel. No aging effects were identified from this review beyond those identified in Subsection 3.6.1. In particular, the review did not identify any instances where insulated cables or connections have failed due to heat-, radiation-, or moisture-related aging effects.

3.6.3 CONCLUSION

The review of industry information, NRC generic communications, and St. Lucie Units 1 and 2 operating experience identified no additional aging effects beyond those discussed in Subsection 3.6.1. Table 3.6-5 contains the results of the aging management review for electrical/I&C components and summarizes that there are no aging effects requiring management for electrical/I&C components. Based on the aging management review, the intended functions of electrical/I&C components will be maintained consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.6.4 REFERENCES

3.6-1 SAND 96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations," Sandia National Laboratories for the U. S. Department of Energy, September 1996.

3.6-2 C. I. Grimes (NRC) letter to D. J. Walters (NEI), "License Renewal Issue No. 98-0013, Degradation Induced Human Activities," June 5, 1998.

3.6-3 EPRI NP-1558, "A Review of Equipment Aging Theory and Technology," Electric Power Research Institute, September 1980.

3.6-4 NUREG/CR-6384, "Literature Review of Environmental Qualification of Safety-Related Electric Cables," Vol. 1, Brookhaven National Laboratory for the U.S. Nuclear Regulatory Commission, April 1996.

TABLE 3.6-1
POTENTIAL AGING EFFECTS
ADAPTED FROM DOE CABLE AMG, TABLE 4-18

Voltage Category[1]	Component	Applicable Stressor	Potential Aging Effects
Low voltage	Metal connector contact surfaces	Moisture and oxygen	Increased resistance and heating; loss of circuit continuity
	Compression fitting	Vibration Tensile stress	Loss of circuit continuity High resistance
Medium voltage	Insulation (cable and connections)	Moisture and voltage stress	Electrical failure (breakdown of insulation)
Medium and low voltages	Insulation (cable and connections)	Radiation and oxygen	Reduced insulation resistance; electrical failure
		Heat and oxygen	Reduced insulation resistance; electrical failure

NOTE: 1. Low voltage: less than 2kV; medium voltage: 2kV to 15kV

TABLE 3.6-2
MOISTURE EXPOSURE SOURCES

Structure	Environment	Potential Moisture Exposure Source
Turbine Buildings Intake Structures Steam Trestle Areas Unit 1 Component Cooling Water Area Yard Structures Ultimate Heat Sink Dam Unit 1 Condensate Storage Tank Enclosure	Outdoor	Precipitation
Yard Structures	Indoor - not air conditioned (wetted)	Standing water in duct banks
Containments Auxiliary Buildings Fuel Handling Buildings Yard Structures	Borated water leaks	Systems containing boric acid

TABLE 3.6-3
INSULATION MATERIAL
RADIATION EXPOSURE COMPARISON

Insulation Material	Maximum Operating Dose	Moderate Damage Dose	Additional Information
EP	4.5×10^5 rads	5×10^7 rads	
EPR, EPDM, FR-EP	1.05×10^6 rads	5×10^7 rads	
Fiberglass (mineral insulated)	1.05×10^6 rads	None	Fiberglass is spun glass and, except for some changes in color, is not affected by radiation.
Glass	1.05×10^6 rads	None	Glass is spun glass and, except for some changes in color, is not affected by radiation.
Kerite-FR3	1.05×10^6 rads	1×10^8 rads	Although no value for Kerite is listed in DOE Cable AMG, Table 4-7, the insulation material has been tested many times for the nuclear power industry at total doses in excess of 1×10^8 rads. This value is used as the moderate damage dose.
Kerite-HTK, Kerite-FR, Kerite-FR2	2.7×10^6 rads	1×10^8 rads	Although no value for Kerite is listed in DOE Cable AMG, Table 4-7, the insulation material has been tested many times for the nuclear power industry at total doses in excess of 1×10^8 rads. This value is used as the moderate damage dose.
Melamine	1.05×10^6 rads	5×10^7 rads	
Phenolic	1.05×10^6 rads	$\sim 4 \times 10^7$ rads	The radiation resistance of phenolic varies depending on what it is "filled" with (e.g., glass, asbestos). The values for "unfilled" phenolic are chosen since it is the least resistent.
Silicon rubber	1.05×10^6 rads	3×10^6 rads	
FR-XLPE	4.5×10^5 rads	1×10^8 rads	
XLPE, XLP, Vulkene	1.05×10^6 rads	1×10^8 rads	
Butyl	4.5×10^5 rads	5×10^6 rads	
Hypalon	1.05×10^6 rads	2×10^6 rads	
Kapton	1.05×10^6 rads	2×10^8 rads	
Nylon	1.05×10^6 rads	2×10^6 rads	There are many formulations of nylon, a material originally developed by the DuPont Company. The values used here are for the most common formulation (general purpose) of nylon that is referred to as Nylon 66 and is designated Zytel 101. Zytel is the DuPont trademark for many different nylon resins.
PE	4.5×10^5 rads	2×10^7 rads	
PVC	4.5×10^5 rads	2×10^7 rads	
Tefzel	1.05×10^6 rads	3×10^7 rads	

TABLE 3.6-4
INSULATION MATERIAL
TEMPERATURE EXPOSURE COMPARISON

Insulation Material	Maximum Cable Temperature [1]	Maximum Temperature For 60-Year Life	60-Year Endpoint
Phenolic	162.0°F (72.0°C)	220.5°F (104.7°C)	50% Retention of Impact Strength
Vulkene	120.0°F (48.9°C)	188.1°F (86.7°C)	60% Retention-of-Elongation
XLPE	162.0°F (72.0°C)	188.1°F (86.7°C)	60% Retention-of-Elongation
Kapton	162.0°F (72.0°C)	248.0°F (120.0°C)	Failure
EP, FR-EP	120.0°F (48.9°C)	154.9°F (68.3°C)	40% Retention-of-Elongation
EPDM	162.0°F (72.0°C)	154.9°F (68.3°C)	40% Loss-of-Elongation
EPR	162.0°F (72.0°C)	154.9°F (68.3°C)	40% Retention-of-Elongation
Kerite-FR3	120.0°F (48.9°C)	166.6°F (74.8°C)	20% Retention-of-Elongation
Kerite-HTK	162.0°F (72.0°C)	185.4°F (85.2°C)	20% Retention-of-Elongation
Melamine	162.0°F (72.0°C)	205.0°F (96.2°C)	25% Reduction in Cross Breaking Strength
PE	104.0°F (40.0°C)	131.0°F (55.0°C)	T_{75} Induction Period
Butyl	104.0°F (40.0°C)	125.1°F (51.7°C)	40% Retention-of-Elongation
Kerite-FR	120.0°F (48.9°C)	141.5°F (60.8°C)	50% Retention-of-Elongation
Silicon rubber	162.0°F (72.0°C)	273.0°F (133.9°C)	50% Retention-of-Elongation
Tefzel	162.0°F (72.0°C)	226.0°F (108.0°C)	50% Retention-of-Elongation
Kerite-FR2	162.0°F (72.0°C)	192.5°F (89.2°C)	20% Retention-of-Elongation
XLP, FR-XLPE	120.0°F (48.9°C)	185.4°F (85.2°C)	60% Retention-of-Elongation
Nylon	120.0°F (48.9°C)	129.9°F (54.4°C)	28% Retention of Tensile Strength
PVC	104.0°F (40.0°C)	112.0°F (44.4°C)	Mean-Time-To-Failure
Hypalon	162.0°F (72.0°C)	154.0°F (67.8°C)	50% Retention-of-Elongation
Glass, Fiberglass (mineral insulated)	Not required	Does not age from heat	Not applicable

NOTE: 1. Maximum Cable Temperature includes self-heating temperature rise for cable insulation in power applications.

TABLE 3.6-5
ELECTRICAL/I&C COMPONENTS AGING MANAGEMENT REVIEW SUMMARY

Component / Commodity Group	Intended Function	Insulation Material	Environment [1]	Aging Effect Requiring Management	Program/Activity
Non-environmentally qualified cables and connections (electrical power circuits)	To electrically connect specified sections of an electrical circuit to deliver voltage, current, or signal	EPR, EPDM, Kerite-FR2, Kapton, Kerite-HTK, XLPE, phenolic, Melamine, glass, Tefzel, Hypalon, and silicone rubber	Moisture Temperature Elevated temperature Ohmic heating Radiation	None	None required
Non-environmentally qualified cables and connections (I&C circuits)	To electrically connect specified sections of an electrical circuit to deliver voltage, current, or signal	Butyl, EP, EPR, EPDM, Kerite-FR, Kerite-FR2, Kerite-FR3, FR-EP, Melamine, nylon, fiberglass, Hypalon, Kapton, PE, Kerite-HTK, phenolic, PVC, XLP, XLPE, Vulkene, FR-XLPE, Tefzel, and silicone rubber	Moisture Temperature Elevated temperature Radiation	None	None required
Uninsulated ground conductors	To electrically connect specified sections of an electrical circuit to deliver voltage, current, or signal	Uninsulated copper	Moisture Temperature Elevated temperature Radiation	None	None required

NOTE 1: All environments are external except ohmic heating, which is considered an internal environment.

4.0 TIME-LIMITED AGING ANALYSES

Two areas of technical review are required to support an application for a renewed operating license. The first area of technical review is the St. Lucie Integrated Plant Assessment, which is described in Chapters 2 and 3. The second area of technical review required for license renewal is the identification and evaluation of plant-specific TLAAs and exemptions, which are provided in this chapter. The evaluations included in this chapter meet the requirements contained in 10 CFR 54.21(c) and allow the NRC to make the finding contained in 10 CFR 54.29(a)(2).

4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c) requires an evaluation of TLAAs be provided as part of the application for a renewed license. TLAAs are defined in 10 CFR 54.3 as those licensee calculations and analyses that:

- Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
- Consider the effects of aging;
- Involve time-limited assumptions defined by the current operating term, for example, 40 years;
- Were determined to be relevant by the licensee in making a safety determination;
- 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 10 CFR 54.4(b); and
- Are contained or incorporated by reference in the current licensing basis.

4.1.1 TIME-LIMITED AGING ANALYSES IDENTIFICATION PROCESS

The process used to identify the St. Lucie-specific TLAAs is consistent with the guidance provided in NEI 95-10 [Reference 4.1-1]. Analyses and evaluations that meet the six criteria of 10 CFR 54.3 were identified from the Technical Specifications, UFSARs, and docketed licensing correspondence. The analyses and evaluations that meet all six criteria of 10 CFR 54.3 are the St. Lucie-specific TLAAs listed in Table 4.1-1.

As required by 10 CFR 54.21(c)(1), an evaluation of St. Lucie-specific TLAAs must be performed to demonstrate that:

(i) the analyses remain valid for the period of extended operation;

(ii) the analyses have been projected to the end of the period of extended operation; or

(iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The results of these evaluations are provided in Table 4.1-1 and discussed in Sections 4.2 through 4.6.

4.1.2 IDENTIFICATION OF EXEMPTIONS

The requirements of 10 CFR 54.21(c) also stipulate that the application for a renewed license include a list of plant-specific exemptions, granted pursuant to 10 CFR 50.12 and in effect, that are based on TLAAs as defined in 10 CFR 54.3. The identification was performed by evaluating the basis for each active 10 CFR 50.12 exemption to determine whether the exemption was based on a time-limited aging analysis. No 10 CFR 50.12 exemptions involving a TLAA as defined in 10 CFR 54.3 were identified for St. Lucie Units 1 and 2.

4.1.3 REFERENCES

4.1-1 NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, Nuclear Energy Institute, March 2001.

TABLE 4.1-1
TIME-LIMITED AGING ANALYSES

TLAA Category	Analysis	Resolution [10 CFR 54.21(c)(1) Section]	Section
Reactor Vessel Neutron Embrittlement	Upper-Shelf Energy	(ii) projected to the end of the period of extended operation	4.2.1
	Pressurized Thermal Shock	(ii) projected to the end of the period of extended operation	4.2.2
	Pressure-Temperature Limits	(ii) projected to the end of the period of extended operation[1]	4.2.3
Metal Fatigue	ASME Section III, Class 1 Components	(i) remains valid for the period of extended operation	4.3.1
	ASME Section III, Class 2 and 3 and ANSI B31.1 Components	(i) remains valid for the period of extended operation	4.3.2
	ASME Section III, Class 2 and 3 and ANSI B31.1 Components - Unit 1 and Unit 2 Reactor Coolant System Sample Lines	(ii) projected to the end of the period of extended operation	4.3.2
Environmental Qualification of Electric Equipment	Alpha Wire and Cable	(ii) projected to the end of the period of extended operation	4.4.1.1
	Amerace Terminal Blocks	(ii) projected to the end of the period of extended operation	4.4.1.2
	Anchor Darling Valve Operators	(ii) projected to the end of the period of extended operation	4.4.1.3
	ASCO Normally De-Energized Solenoid Valves; Models 206-381 and NP-8320	(ii) projected to the end of the period of extended operation	4.4.1.4
	ASCO Normally De-Energized Solenoid Valves; Models NP-8316, NP-8321, and NP-8344	(ii) projected to the end of the period of extended operation	4.4.1.5
	Boston Insulated Wire Cables	(ii) projected to the end of the period of extended operation	4.4.1.6
	Cerro (Rockbestos) Cables	(ii) projected to the end of the period of extended operation	4.4.1.7
	Cerro (Rockbestos) Coaxial/Triaxial Cables	(ii) projected to the end of the period of extended operation	4.4.1.8
	Combustion Engineering Mineral Insulated Cables and Connectors	(ii) projected to the end of the period of extended operation	4.4.1.9
	Conax Conduit Seals	(ii) projected to the end of the period of extended operation	4.4.1.10
	Conax Penetrations	(ii) projected to the end of the period of extended operation	4.4.1.11

NOTE: 1. Although 60-year pressure-temperature limits are not being submitted as part of this application, updated pressure-temperature limits will be submitted prior to entering the period of extended operation.

TABLE 4.1-1 (continued)
TIME-LIMITED AGING ANALYSES

TLAA Category	Analysis	Resolution [10 CFR 54.21(c)(1) Section]	Section
Environmental Qualification of Electric Equipment (continued)	Conax Thermocouples	(ii) projected to the end of the period of extended operation	4.4.1.12
	Continental Cables	(ii) projected to the end of the period of extended operation	4.4.1.13
	CVI Heaters	(ii) projected to the end of the period of extended operation	4.4.1.14
	EGS Grayboot Connectors	(ii) projected to the end of the period of extended operation	4.4.1.15
	Fluid Control Incorporated Level Sensors	(ii) projected to the end of the period of extended operation	4.4.1.16
	General Atomic Radiation Monitors	(ii) projected to the end of the period of extended operation	4.4.1.17
	General Cable Cables	(ii) projected to the end of the period of extended operation	4.4.1.18
	General Electric Cables	(ii) projected to the end of the period of extended operation	4.4.1.19
	General Electric High Pressure Safety Injection (Unit 1) and Auxiliary Feedwater Pump Motors	(ii) projected to the end of the period of extended operation	4.4.1.20
	General Electric High Pressure Safety Injection (Unit 2) Pump Motors	(ii) projected to the end of the period of extended operation	4.4.1.21
	General Electric Terminal Blocks	(ii) projected to the end of the period of extended operation	4.4.1.22
	Gordon Thermocouples	(ii) projected to the end of the period of extended operation	4.4.1.23
	Gulf General Atomic Electrical Penetrations	(ii) projected to the end of the period of extended operation	4.4.1.24
	IMO Industries Level Sensors	(ii) projected to the end of the period of extended operation	4.4.1.25
	Indeeco Heaters	(ii) projected to the end of the period of extended operation	4.4.1.26
	Kerite Cables (HTK/FR/FR2 Insulation)	(ii) projected to the end of the period of extended operation	4.4.1.27
	Limitorque Valve Operators	(ii) projected to the end of the period of extended operation	4.4.1.28
	Magnetrol Level Switches	(ii) projected to the end of the period of extended operation	4.4.1.29
	Micro Switch Limit Switches	(ii) projected to the end of the period of extended operation	4.4.1.30

TABLE 4.1-1 (continued)
TIME-LIMITED AGING ANALYSES

TLAA Category	Analysis	Resolution [10 CFR 54.21(c)(1) Section]	Section
Environmental Qualification of Electric Equipment (continued)	Okonite Cables (EPR Insulation)	(ii) projected to the end of the period of extended operation	4.4.1.31
	Okonite Cables (X-Olene FMR Insulation)	(ii) projected to the end of the period of extended operation	4.4.1.32
	Raychem Cables	(ii) projected to the end of the period of extended operation	4.4.1.33
	Raychem Splices	(ii) projected to the end of the period of extended operation	4.4.1.34
	RdF Resistance Temperature Detectors	(ii) projected to the end of the period of extended operation	4.4.1.35
	Reliance Electric Containment Fan Cooler Motors	(ii) projected to the end of the period of extended operation	4.4.1.36
	Rome Cables	(ii) projected to the end of the period of extended operation	4.4.1.37
	Siemens Allis Containment Spray Pump Motors	(ii) projected to the end of the period of extended operation	4.4.1.38
	Target Rock Normally De-Energized Solenoid Valves; Series 80B	(ii) projected to the end of the period of extended operation	4.4.1.39
	Target Rock Normally De-Energized Solenoid Valves; Series 74Q, 76R, 78E, 84V, 89Q, and 98K	(ii) projected to the end of the period of extended operation	4.4.1.40
	TEC Acoustic Flow Monitor - Accelerometer and Cable Assembly	(ii) projected to the end of the period of extended operation	4.4.1.41
	Teledyne Thermatics Cable	(ii) projected to the end of the period of extended operation	4.4.1.42
	3M Tape Splices	(ii) projected to the end of the period of extended operation	4.4.1.43
	Valcor Normally De-Energized Solenoid Valves	(ii) projected to the end of the period of extended operation	4.4.1.44
	Weed Resistance Temperature Detectors	(ii) projected to the end of the period of extended operation	4.4.1.45
	Westinghouse Charging Pump Motors	(ii) projected to the end of the period of extended operation	4.4.1.46
	Westinghouse Containment Fan Cooler Motors	(ii) projected to the end of the period of extended operation	4.4.1.47
	Westinghouse Hydrogen Recombiner	(ii) projected to the end of the period of extended operation	4.4.1.48

TABLE 4.1-1 (continued)
TIME-LIMITED AGING ANALYSES

TLAA Category	Analysis	Resolution [10 CFR 54.21(c)(1) Section]	Section
Environmental Qualification of Electric Equipment (continued)	Westinghouse Low Pressure Safety Injection Pump Motors	(ii) projected to the end of the period of extended operation	4.4.1.49
	Westinghouse Ventilation Fan Motors	(ii) projected to the end of the period of extended operation	4.4.1.50
	United Control International Silicone Tape	(ii) projected to the end of the period of extended operation	4.4.1.51
Metal Containment and Penetration Fatigue	Penetration Fatigue	(i) remains valid for the period of extended operation	4.5.2
Other Plant-Specific TLAAs	Leak-Before-Break for Reactor Coolant System Piping	(i) remains valid for the period of extended operation	4.6.1
	Crane Load Cycle Limit	(i) remains valid for the period of extended operation	4.6.2
	Unit 1 Core Support Barrel Repair Fatigue	(i) remains valid for the period of extended operation	4.6.3
	Unit 1 Core Support Barrel Repair Plug Preload Relaxation	(ii) projected to the end of the period of extended operation	4.6.3
	Alloy 600 Instrument Nozzle Repairs	(i) remains valid for the period of extended operation	4.6.4

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT

This group of TLAAs concerns the effect of irradiation embrittlement on the beltline regions of the St. Lucie Units 1 and 2 reactor vessels, and how this mechanism affects analyses that provide operating limits or address regulatory requirements. The calculations discussed in this section use predictions of the cumulative effects on the reactor vessels from irradiation embrittlement. The calculations are based on periodic assessment of the neutron fluence and resultant changes in the reactor vessel material fracture toughness.

The intermediate and lower shells and the welds that join them in the beltline region (adjacent to the reactor core) of the reactor vessels are fabricated from low alloy steels. These ferritic steels exhibit a ductile-brittle transition that results in fracture toughness property changes as a function of both temperature and irradiation. The material property of particular importance in assessing reactor vessel integrity is fracture toughness, which can be defined as the capability of a material to resist sudden failure caused by crack propagation. Fracture toughness is reduced by neutron irradiation. The measure of fracture toughness of the reactor vessel materials when the reactor vessel is above the brittle fracture/ductile failure transition temperature is referred to as upper-shelf energy. Upper-shelf energy is related to the ability of a material to resist ductile tearing. In addition, the temperature at which the brittle fracture/ductile failure transition occurs increases with increasing radiation.

This shift in the transition temperature is referred to as the shift in reference nil ductility transition temperature (RT_{NDT}). The effect of embrittlement due to neutron bombardment is evaluated for reactor vessel temperatures throughout the range of normal operating values. Heatup and cooldown curves consider normal, relatively slow thermal transients. PTS transients are characterized by a rapid and significant decrease in reactor coolant temperature with high pressure in the reactor vessel. The high reactor vessel thermal stresses, when combined with the pressure stresses, are assumed to initiate the propagation of a small flaw that is postulated to exist in the reactor vessel beltline. Postulated high pressures could cause propagation of the flaw through the reactor vessel wall.

The welds in the reactor vessels are basically the same material as the parts being joined and may be considered to be included in the preceding discussions. The chemistry differences between weld metal and base metal affect the material properties that are degraded by embrittlement; therefore, the welds are evaluated separately when considering the aforementioned aging effect.

The best estimate maximum projected fast (>1.0 MeV) neutron fluence for the St. Lucie Units 1 and 2 reactor vessels has been calculated for the period of extended operation assuming 54 effective full power years (EFPY) or greater, which is a conservative estimate of plant operation for a 60 year end-of-life (EOL). These fluence projections will be used to address the ability of the reactor vessels to meet the requirements of NRC Regulatory Guide 1.99, Revision 2, " Radiation Embrittlement of Reactor Vessel Materials."

The St. Lucie Units 1 and 2 reactor vessel materials irradiation surveillance program is described in Unit 1 UFSAR Section 5.4.4, and Unit 2 UFSAR Section 5.3.1.6. Irradiation surveillance programs are utilized on both Units to assess the irradiation-induced changes in the strength and toughness properties of the reactor vessel beltline materials and to determine if the requirements of 10 CFR 50, Appendices G and H, are met. Changes in the reactor vessel material properties are evaluated by comparing pre- and post-irradiation specimens. Revisions to the capsule surveillance schedules for Units 1 and 2, consistent with 10 CFR 50, Appendix H, will be required for the period of extended operation. These changes are discussed in Subsection 3.2.12.1 of Appendix B.

Irradiation surveillance capsules attached to the inner reactor vessel walls contain specimens representative of the limiting vessel beltline materials under conditions that represent the approximate irradiation conditions of the reactor vessel. The capsules also contain neutron dosimetry for monitoring the time-integrated neutron fluence. Presently, reactor vessel toughness, as measured by the Adjusted Reference Temperature (ART), is predicted by the methods in NRC Regulatory Guide 1.99, Revision 2.

4.2.1 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G, requires licensees to submit an analysis at least 3 years prior to the time that the USE of any of the reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing. The lower USE concern is associated with the determination of acceptable reactor vessel toughness during the license renewal period when the vessel is exposed to additional irradiation.

Only the intermediate- and lower-shell plates and connecting welds (beltline materials) need to be evaluated for embrittlement since the fluence drops off rapidly with distance from the core midplane.

The USE values of the vessel beltline materials presented in Tables 4.2-1 and 4.2-2 demonstrate that St. Lucie Units 1 and 2 reactor vessel beltline materials remain acceptably above the 10 CFR 50, Appendix G, USE limit of 50 ft-lbs.

The analyses associated with USE have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.2 PRESSURIZED THERMAL SHOCK

The requirements in 10 CFR 50.61 provide rules for protection against PTS events for PWRs. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS} or upon request for a change in the expiration date for the operation of the facility.

The methods for calculating RT_{PTS} values are given in 10 CFR 50.61 and are consistent with the methods in Regulatory Guide 1.99, Revision 2, " Radiation Embrittlement of Reactor Vessel Materials." These accepted methods were used to calculate the RT_{PTS} for the St. Lucie Units 1 and 2 reactor vessel limiting materials at the end of the 60 year period of operation using a conservatively bounding fluence. Only the intermediate- and lower-shell plates and connecting welds (beltline materials) need to be evaluated for embrittlement since the fluence drops off rapidly with distance from the core midplane. The calculated RT_{PTS} values for the St. Lucie reactor vessels at the end of the period of extended operation are presented in Tables 4.2-3 and 4.2-4.

The calculated RT_{PTS} values at the 60-year EOL for the St. Lucie Units 1 and 2 reactor vessels are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for the intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the St. Lucie reactor vessels during the license renewal period.

The analyses associated with PTS have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, stipulate that heatup and cooldown of the reactor vessels be accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor vessels become embrittled and their fracture toughness is reduced, the allowable pressure is reduced. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within the limits of Appendix G defined by the reactor vessel fluence.

The fluence and material properties were used to determine the limiting material and calculate the current pressure-temperature limits for St. Lucie Units 1 and 2 at 23.6 EFPY and 21.7 EFPY, respectively. The resulting heatup and cooldown pressure-temperature limits are presented in the Units 1 and 2 Technical Specifications. The pressure-temperature limits for St. Lucie Units 1 and 2 will be updated to bound the operating periods as the operating schedules require. In addition, the low temperature overpressure protection system and overpressure mitigation system requirements will be updated to ensure that the pressure-temperature limits are not exceeded for postulated plant transients.

In accordance with NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" [Reference 4.2-1], Section 4.2.2.1.3.3 updated pressure-temperature limits for the period of extended operation must be available prior to entering the period of extended operation. It is not necessary to implement pressure-temperature limits to carry the reactor vessels through 60 years at the time of application.

The analyses associated with reactor vessel pressure-temperature limits for St. Lucie Units 1 and 2 will be available prior to entering the period of extended operation, in accordance with the requirements of the Reactor Vessel Integrity Program and consistent with 10 CFR 54.21(c)(1)(ii).

4.2.4 REFERENCES

4.2-1 NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," U. S. Nuclear Regulatory Commission, April 2001.

TABLE 4.2-1
ST. LUCIE UNIT 1 - 60-YEAR EOL USE VALUES FOR THE BELTLINE MATERIALS
(USE Method: Reg. Guide 1.99, Rev. 2, Position 1.2, Graph)

Location	Weight % of Cu	Transverse Initial USE (ft-lbs)	EOL 1/4T Fluence ($x10^{19}$ n/cm^2)	Projected % USE Decrease	EOL 1/4T USE (ft-lbs)
Lower shell plate (C-8-1)	0.15	82	2.79	31	56.5
Lower shell plate (C-8-2)	0.15	103	2.79	31	71.1
Lower shell plate (C-8-3)	0.12	88	2.79	27	64.5
Intermediate shell plate (C-7-1)	0.11	82	2.79	26	60.6
Intermediate shell plate (C-7-2)	0.11	82	2.79	26	60.6
Intermediate shell plate (C-7-3)	0.11	76	2.79	26	56.3
Lower shell axial welds (3-203A,B,C)	0.27	112	1.84	47	59.4
Intermediate shell axial welds (2-203A,B,C)	0.19	102	1.84	38	63.4
Intermediate to lower girth welds (9-203)	0.27	144	2.79	49	73.4

TABLE 4.2-2
ST. LUCIE UNIT 2 - 60-YEAR EOL USE VALUES FOR THE BELTLINE MATERIALS
(USE Method: Reg. Guide 1.99, Rev. 2, Position 1.2, Graph)

Location	Weight % of Cu	Transverse Initial USE (ft-lbs)	EOL 1/4T Fluence ($x10^{19}$ n/cm^2)	Projected % USE Decrease	EOL 1/4T USE (ft-lbs)
Lower shell plate (M-4116-1)	0.06	91	2.91	24	69.2
Lower shell plate (M-4116-2)	0.07	105	2.91	24	79.8
Lower shell plate (M-4116-3)	0.07	100	2.91	24	76.0
Intermediate shell plate (M-605-1)	0.11	105	2.91	26	77.7
Intermediate shell plate (M-605-2)	0.13	113	2.91	28	81.4
Intermediate shell plate (M-605-3)	0.11	113	2.91	26	83.6
Intermediate shell axial welds (101-124A,B,C)	0.05	116	2.91	24	88.2
Intermediate shell axial welds (101-124C Repair)	0.05	136	2.91	24	103.4
Lower shell axial welds (101-142A,B,C)	0.05	136	2.91	24	103.4
Intermediate to lower girth welds (101-171)	0.07	96	2.91	27	70.1
Intermediate to lower girth welds (101-171)	0.05	115	2.91	24	87.4
Intermediate to lower girth welds (101-171)	0.07	96	2.91	27	70.1

TABLE 4.2-3
ST. LUCIE UNIT 1 - 60 YEAR EOL RT_{PTS} VALUES FOR THE BELTLINE MATERIALS

Location	Chemistry Factor	Initial RT_{NDT} (°F)	Margin	EOL Peak Fleunce ($x10^{19}$ n/cm^2)	Fluence Factor	Delta RT_{PTS} (°F)	EOL RT_{PTS} (°F)
Lower shell plate (C-8-1)	78.3 (Note 1)	20	17	4.68	1.39	109	146
Lower shell plate (C-8-2)	78.7 (Note 1)	20	17	4.68	1.39	109	146
Lower shell plate (C-8-3)	60.0 (Note 1)	0	17	4.68	1.39	83	100
Intermediate shell plate (C-7-1)	74.6	0	34	4.68	1.39	104	138
Intermediate shell plate (C-7-2)	74.6	-10	34	4.68	1.39	104	128
Intermediate shell plate (C-7-3)	73.8	10	34	4.68	1.39	103	147
Lower shell axial welds (3-203A,B,C)	188.8	-60	56	3.08	1.30	245	241
Intermediate shell axial welds (2-203A,B,C)	90.7	-56	65	3.08	1.30	118	127
Intermediate to lower girth weld (9-203)	69.9 (Note 1)	-60	28	4.68	1.39	97	65

NOTES: 1. Calculated chemistry factors used for these locations, other locations utilize chemistry factors from 10 CFR 50.61 tables.

TABLE 4.2-4
ST. LUCIE UNIT 2 - 60 YEAR EOL RT_{PTS} VALUES FOR THE BELTLINE MATERIALS

Location	Chemistry Factor (Note 1)	Initial RT_{NDT} (°F)	Margin	EOL Peak Fleunce ($x10^{19}$ n/cm^2)	Fluence Factor	Delta RT_{PTS} (°F)	EOL RT_{PTS} (°F)
Lower shell plate (M-4116-1)	37.0	20	34	4.89	1.40	52	106
Lower shell plate (M-4116-2)	44.0	20	34	4.89	1.40	62	116
Lower shell plate (M-4116-3)	44.0	20	34	4.89	1.40	62	116
Intermediate shell plate (M-605-1)	74.2	30	34	4.89	1.40	104	168
Intermediate shell plate (M-605-2)	91.5	10	34	4.89	1.40	128	172
Intermediate shell plate (M-605-3)	74.2	0	34	4.89	1.40	104	138
Intermediate shell axial welds (101-124A,B,C)	36.4	-56 (Note 2)	51	4.89	1.40	51	46
Intermediate shell axial welds (101-124C Repair)	34.1	-50	48	4.89	1.40	48	45
Lower shell axial welds (101-142A,B,C)	34.1	-50	48	4.89	1.40	48	45
Intermediate to lower girth welds (101-171)	40.1	-50 (Note 3)	56	4.89	1.40	56	62

NOTES:
1. Chemistry factors from 10 CFR 50.61 tables.
2. Generic RT_{NDT} value.
3. The RT_{NDT} of –50°F represents the highest value from surveillance weld data.

4.3 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for St. Lucie Units 1 and 2. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the St. Lucie Units 1 and 2 UFSARs.

4.3.1 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 1 COMPONENTS

The reactor vessels (including control element drive mechanisms), reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and Unit 2 reactor coolant piping have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The St. Lucie Unit 1 reactor coolant piping was originally designed in accordance with ANSI B 31.7, "Nuclear Power Piping." The St. Lucie Units 1 and 2 pressurizer surge lines were reanalyzed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." These design codes require a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded.

St. Lucie Unit 1 reactor vessel internals fatigue is addressed in Subsection 4.6.3.

Fatigue usage factors for critical locations in the St. Lucie Units 1 and 2 Nuclear Steam Supply System Class 1 components were determined using design cycles that were specified in the plant design process or as a result of industry fatigue issues (e.g., thermal stratification). These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for the Class 1 components satisfying ASME fatigue usage design requirements.

Experience has shown that actual plant operation is often very conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the period of extended operation, the design cycles applicable to the Class 1 components were assembled.

The actual frequency of occurrence for the fatigue-sensitive design cycles was determined and compared to the design cycle set. The severity of the actual plant cycles was also compared to the severity of the design cycles. This comparison was performed in order to demonstrate that on an event-by-event basis the design cycle profiles envelope actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the Fatigue Monitoring Program. The reviews described above concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the structural integrity of the Class 1 components have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. If 80% of a design cycle limit is reached, this program will require plant management review to determine appropriate actions. The Fatigue Monitoring Program is considered a confirmatory program.

Flaws in Class 1 components that exceed the size of allowable flaws defined in Subsection IWB-3500 of the ASME Code need not be repaired if they are analytically evaluated to the criteria in Subsection IWB-3600. Currently the only identified flaws in Class 1 components that exceed the allowable flaw limits defined in Subsection IWB-3500 are specific Alloy 600 instrument nozzles. These instrument nozzles are described in Subsection 4.6.4.

4.3.2 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 2 AND 3, AND ANSI B31.1 COMPONENTS

St. Lucie Units 1 and 2 have a number of piping systems within the scope of license renewal that were designed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, ANSI B31.7, "Nuclear Power Piping," or ANSI B31.1, "Power Piping." Subsequently, St. Lucie piping systems originally designed to the requirements of ANSI B31.7, Class 2 and 3 were reconciled to ASME Section III, Class 2 and 3. Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to plant operation. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years.

A review of ASME Section III, Class 2 and 3, and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperatures. Based on the guidance from EPRI [Reference 4.3-1] and industry working groups, any piping system with operating temperature less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Under current plant operating practices, piping systems within the scope of license renewal are generally only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady-state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or for periodic testing. The results of the calculations determined that, except for the Reactor Coolant System hot leg sample piping on each Unit, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. Therefore, the current piping analyses remain valid for the period of extended operation.

The Reactor Coolant System hot leg sample lines on each Unit could exceed the 7000 equivalent full temperature thermal cycles during the period of extended operation based on St. Lucie's current sampling practices. The sample piping and tubing were re-evaluated to consider the projected number of cycles and the analyses were found acceptable for the period of extended operation.

Therefore, except for the Reactor Coolant System hot leg sample lines, the ASME Section III, Class 2 and 3 and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The Reactor Coolant System hot leg sample lines fatigue analyses have been projected to the end of the period of extended operation in accordance with 10CFR54.21(c)(1)(ii).

4.3.3 ENVIRONMENTALLY ASSISTED FATIGUE

Generic Safety Issue (GSI) 190 [Reference 4.3-2] was initiated by the NRC staff because of concerns about the potential effects of reactor water environments on Reactor Coolant System component fatigue life during the period of extended operation. GSI-190 was closed in December 1999 [Reference 4.3-3], and the NRC concluded that environmental effects have a negligible impact on core damage frequency, and as such, no generic regulatory action is required. However, as part of the closure of GSI-190, the NRC concluded that licensees who apply for license renewal should address the effects of coolant environment on component fatigue life as part of their aging management programs [Reference 4.3-4].

Fatigue calculations that include consideration of environmental effects to establish cumulative usage factors could be treated as TLAAs under 10 CFR 54 or they could be utilized to establish the need for an aging management program. In other words, the determination of whether a particular component location is to be included in a program for managing the effects of fatigue, and the characteristics of that program, should incorporate reactor water environmental effects.

An analysis must satisfy all six criteria defined in 10 CFR 54.3 to qualify as a TLAA. Failure to satisfy any one of these criteria eliminates the analysis from further consideration as a TLAA. Fatigue design analysis for St. Lucie Units 1 and 2 has been determined to be a TLAA, even though the design limits are based on cycles rather than an explicit time period. However, reactor water environmental effects, as described in GSI-190, are not included in the St. Lucie Units 1 and 2 CLBs, such that the criterion specified in 10 CFR 54.3(a)(6) is not satisfied. Nevertheless, environmental effects on Class 1 component fatigue have been evaluated separately for St. Lucie to determine if any additional actions are required for the period of extended operation.

The FPL approach to address reactor water environmental effects at St. Lucie Units 1 and 2 accomplishes two objectives, as illustrated in Figure 4.3-1. First, the TLAA on fatigue design has been resolved by confirming that the original design cycles remain valid for the 60-year operating period (see Subsection 4.3.1 on Class 1 metal fatigue). Confirmation by the Fatigue Monitoring Program will ensure these design cycles are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment. These two aspects of fatigue design are kept separate, since fatigue design is part of the St. Lucie Units 1 and 2 CLBs and a TLAA, while the consideration of reactor water environmental effects on fatigue life, as described in GSI-190, is not considered part of the St. Lucie Units 1 and 2 CLBs.

Three areas of margin included in the St. Lucie Fatigue Monitoring Program are margins resulting from actual cycle experience, cycle severity, and moderate environmental effects.

<u>Margin Due to Actual Cycles</u>: As discussed in Subsection 4.3.1, the original 40-year design cycle set for Class 1 components is valid for the 60-year extended operating period. Conservative projections conclude that the design cycle limits will not be exceeded. Additional margin is available in the current Class 1 component fatigue analyses since the cumulative fatigue usage factors (CUFs) for all Class 1 components remain below the acceptance criterion of 1.0.

Margin Due to Cycle Severity: Much of the conservatism in the fatigue analysis methodology is due to design cycle definitions. As discussed in Subsection 4.3.1, the severity of the original St. Lucie design cycles bound actual plant operation. Additional industry fatigue studies [References 4.3-5 through 4.3-8] conclude that the fatigue impact of conservative design basis cycle definitions by themselves overwhelms the contributing impact of reactor water environmental effects.

Margin Due to Moderate Environmental Effects: A portion of the safety factors applied to the ASME Section III fatigue design curves includes moderate environmental effects. While there is debate over exactly the amount of margin this represents, it is noteworthy to recognize this safety factor in this qualitative discussion of margin.

Considering the three margins above, the St. Lucie Fatigue Monitoring Program is conservative from an overall perspective. Nevertheless, specific assessments of potential environmental effects have been addressed.

Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260 [Reference 4.3-9], fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system (NSSS) vendors, as a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term. The PWR calculations included in NUREG/CR-6260, especially the "Older Vintage Combustion Engineering Plant," closely match St. Lucie with respect to the design codes used. Additionally, the evaluated design cycles considered in the evaluation match or bound the St. Lucie designs.

The fatigue-sensitive component locations chosen in NUREG/CR-6260 for the "Older Vintage Combustion Engineering Plant" were:

1. Reactor vessel shell and lower head
2. Reactor vessel inlet nozzle
3. Reactor vessel outlet nozzle
4. Surge line
5. Charging system nozzle
6. Safety injection system nozzle
7. Shutdown cooling system Class 1 piping

NUREG/CR-6260 calculated fatigue usage factors for these locations utilizing the interim fatigue curves provided in NUREG/CR-5999 [Reference 4.3-10]. However, because the fatigue usage factors evaluated in NUREG/CR-6260 were based on a plant different than St. Lucie, plant-specific usage factor evaluations were performed for St. Lucie. In addition, the data included in more recent industry studies [References 4.3-11 and 4.3-12] need to be considered in the evaluations of environmental effects.

Environmental fatigue calculations have been performed for St. Lucie Units 1 and 2 for those component locations included in NUREG/CR-6260 using the appropriate methods contained in NUREG/CR-6583 [Reference 4.3-11] for carbon/low alloy steel material or NUREG/CR-5704 [Reference 4.3-12] for stainless steel material, as appropriate. Based on these results, all component locations were determined to be acceptable for the period of extended operation, with the exception of the pressurizer surge lines (specifically the surge line elbows below the pressurizers). The pressurizer surge line elbows require further evaluation for the period of extended operation.

FPL has selected aging management to address pressurizer surge line fatigue at St. Lucie Units 1 and 2 during the period of extended operation, in lieu of performing additional analyses to refine the fatigue usage factors. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the extended period of operation by the continued performance of the St. Lucie ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Additionally, specific requirements will be included to evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue (see Appendix B, Subsection 3.2.2.1).

The St. Lucie Units 1 and 2 surge lines are 12-inch schedule 160 lines connected to the pressurizer surge nozzles and to the hot leg surge nozzles. The surge lines contain nine welds. A sample of these surge line welds is currently examined every ten years in accordance with the requirements of ASME Section XI, Subsection IWB. Surge line welds selected for the inservice examinations, by nature of their size, require a volumetric examination in addition to a surface examination. A number of the surge line welds have been examined ultrasonically during inservice examination intervals at St. Lucie. A total of 14 Unit 1 pressurizer surge line weld examinations and 17 Unit 2 pressurizer surge line weld examinations have been performed ultrasonically to date as part of the current ASME Section XI program, including a total of seven inspections on the pressurizer surge line elbow welds (three on Unit 1 and four on Unit 2). No indications were identified.

The limiting pressurizer surge line welds will continue to be inspected during the third and fourth inservice inspection intervals and prior to the license renewal period. The results of those inspections will be utilized to assess continuation of the current ten-year inspection interval for continued use throughout the remaining operating period. Any proposed changes to the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program due to risk-informed inservice inspection would continue to include the limiting pressurizer surge line elbow welds in the inservice inspection scope.

The proposed aging management program to address fatigue of the St. Lucie Units 1 and 2 pressurizer surge lines during the period of extended operation is similar to the approach documented in the ASME Section XI - Rules for Inservice Inspection of Nuclear Power Plant Components, Non-mandatory Appendix L. However, FPL recognizes that, to date, the NRC has not endorsed the Appendix L approach. The primary NRC concerns with Appendix L include crack aspect ratio and acceptable fatigue crack growth rates (including environmental effects).

As noted above, several pressurizer surge line welds on Unit 1 and 2 have been ultrasonically examined. No reportable indications have been identified. In addition, FPL plans to inspect the limiting surge line welds on St. Lucie Units 1 and 2 during the third and fourth inservice inspection interval, and prior to entering the extended period of operation. The results of these inspections will be utilized to assess the appropriate approach for addressing environmentally assisted fatigue of the surge lines. The approach developed could include one or more of the following:

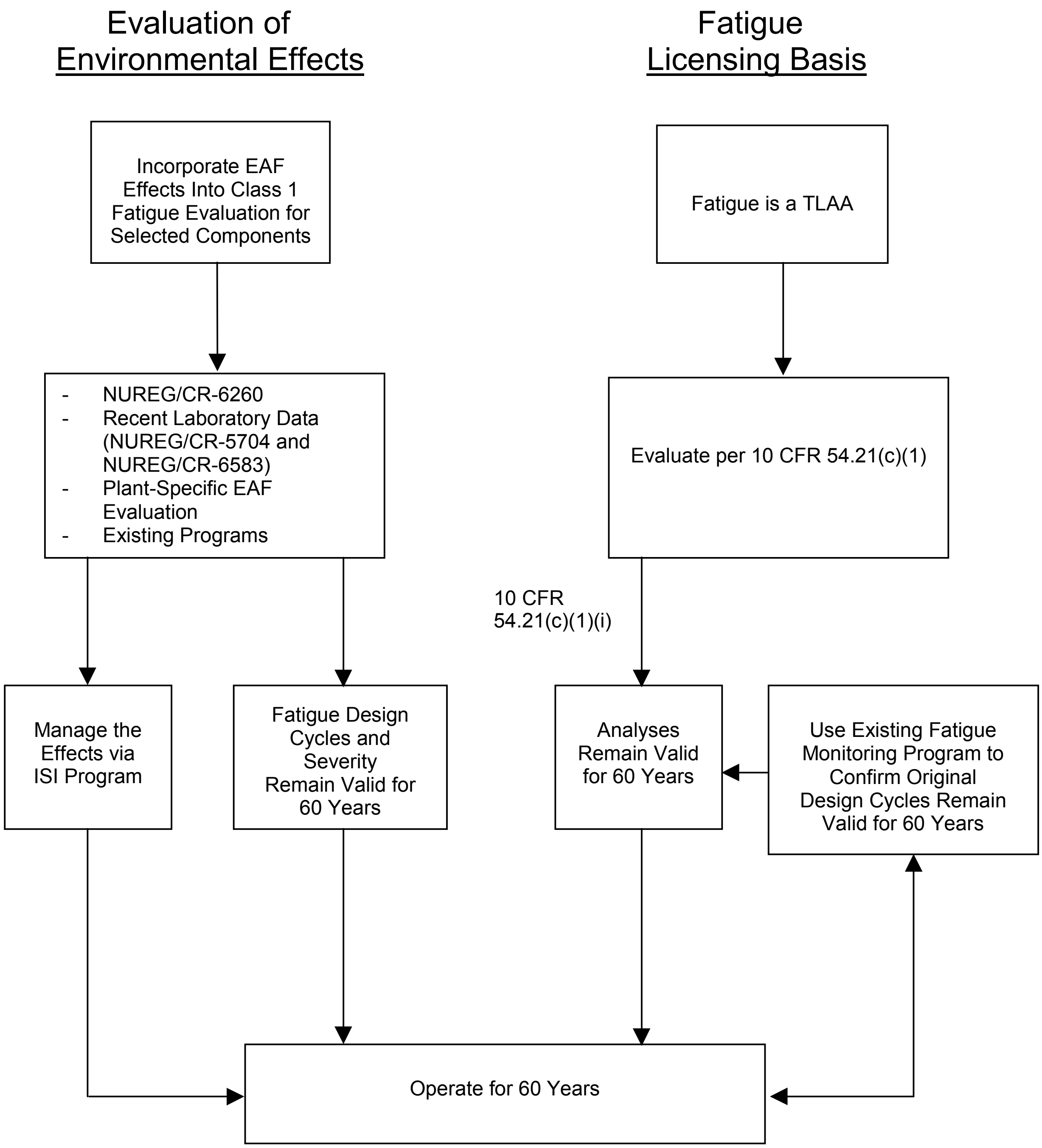
1. Further refinement of the fatigue analyses to lower the CUF(s) to below 1.0, or
2. Repair of the affected locations, or
3. Replacement of the affected locations, or
4. Management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

Should FPL select Option 4 (i.e., inspection) to manage environmentally assisted fatigue during the period of extended operation at St. Lucie Units 1 and 2, inspection details such as scope, qualification, method, and frequency will be provided to the NRC prior to entering the period of extended operation.

The recommended FPL position to address the effects of environmentally assisted fatigue at St. Lucie Units 1 and 2 meets the requirements specified in the NRC closure of GSI-190. The position takes a proactive approach by performing volumetric and surface examinations of the most fatigue-sensitive locations, the pressurizer surge line elbow welds, during both the current period of operation and the license renewal period of extended operation. The commitment to inspect the fatigue-sensitive surge line locations in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides reasonable assurance that potential environmental effects of fatigue will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

FIGURE 4.3-1

GSI-190 EVALUATION PROCESS



4.3.4 REFERENCES

4.3-1 EPRI Report No. TR-104534, "Fatigue Management Handbook", Volumes 1, 2 and 3, Research Project 3321, Revision 1, Electric Power Research Institute, December 1994.

4.3-2 Generic Safety Issue 190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," U. S. Nuclear Regulatory Commission.

4.3-3 Thadani, A. C. (NRC) memorandum to Travers, W. D. (NRC), "Closeout of Generic Safety Issue 190, Fatigue Evaluation of Metal Components for 60 Year Plant Life," U. S. Nuclear Regulatory Commission, December 26, 1999.

4.3-4 Powers, D. A. (ACRS) letter to Travers, W. D. (NRC), "Proposed Resolution of Generic Safety Issue-190, Fatigue Evaluation of Metal Components for 60-Year Plant Life," December 10, 1999.

4.3-5 EPRI Report No. TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," Electric Power Research Institute, January 1998.

4.3-6 EPRI Report No. TR-110043, "Evaluation of Environmental Fatigue Effects for a Westinghouse Nuclear Power Plant," Electric Power Research Institute, April 1998.

4.3-7 EPRI Report No. TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant," Electric Power Research Institute, April 1998.

4.3-8 EPRI Report No. TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components," Electric Power Research Institute, May 1998.

4.3-9 NUREG/CR-6260 (INEL-95/0045), "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," U. S. Nuclear Regulatory Commission, March 1995.

4.3-10 NUREG/CR-5999 (ANL-93/3), "Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments," U. S. Nuclear Regulatory Commission, August 1993.

4.3-11 NUREG/CR-6583 (ANL-97/18), "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," U. S. Nuclear Regulatory Commission, March 1998.

4.3-12 NUREG/CR-5704 (ANL-98/31), "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," U. S. Nuclear Regulatory Commission, April 1999.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

The thermal, radiation, and wear cycle aging analyses of plant electrical/I&C components required to meet 10 CFR 50.49 have been identified as TLAAs for St. Lucie Units 1 and 2.

The NRC has established nuclear station EQ requirements in 10 CFR 50, Appendix A, and in 10 CFR 50.49. The requirements in 10 CFR 50.49 specify that an EQ program be established to demonstrate that certain electrical/I&C components located in "harsh" plant environments (i.e., those areas of the plant that could be subject to the harsh environment effects of a LOCA, high energy line break, or post LOCA radiation) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. Further, 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

All operating plants must meet the requirements of 10 CFR 50.49 for certain electrical/I&C components important to safety. The scope of components to be included is defined in 10 CFR 50.49, which also requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and environmental conditions. The requirements in 10 CFR 50.49(e)(5) contain provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e) also requires component replacement or refurbishment prior to the end of designated life unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. The requirements in 10 CFR 50.49 (k) and (l) permit different criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the DOR Guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" [Reference 4.4-1], NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," and Regulatory Guide 1.89, "Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants," Revision 1. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during accident conditions after experiencing the effects of inservice aging.

The St. Lucie Environmental Qualification Program complies with all applicable regulations and is consistent with the GALL Report [Reference 4.4-2]. However, FPL does not consider the St. Lucie Environmental Qualification Program to be an aging management program, but credits the program as part of the screening process for ensuring the qualified life of electrical/I&C components within the scope of 10 CFR 50.49 is maintained. The St. Lucie Environmental Qualification Program includes three main elements: identifying applicable components and environmental requirements, establishing the qualification, and maintaining (or preserving) that qualification.

The first element involves establishment and control of the Environmental Qualification List of components and the service conditions for the harsh environment plant areas. The second element involves establishment and control of the components' EQ documentation, including vendor test reports, vendor correspondence, calculations, evaluations of component tested conditions to plant required conditions, and determinations of configuration and maintenance requirements. The third element includes preventive maintenance processes (for replacing parts and components at specified intervals), design control processes (ensuring changes to the plant are evaluated for impact to the Environmental Qualification Program), procurement processes (ensuring new and replacement components are purchased to applicable EQ requirements), and corrective action processes in accordance with the FPL Quality Assurance Program. As part of the design control aspect of the Environmental Qualification Program, any plant modification that could affect the qualification of a component in the program is addressed and resolved in the modification package. Similarly for events, the effect on the qualification is addressed and resolved by the corrective action process. These controls assure any environmental changes occurring due to plant modifications and events are properly dispositioned for the remainder of the current license and throughout the renewal period.

There have not been any major plant modifications or events at St. Lucie Units 1 and 2 of sufficient duration to change the normal temperature and radiation values that were used in the underlying assumptions in the EQ calculations due to the conservative profile of the temperature and radiation values used. In 1994 and 2000, FPL increased the EQ design basis accident temperature profile for Unit 1 in response to Loss of Coolant and Main Steam Line Break reanalyses that increased the required temperature profile. The EQ components inside Containment were then shown to meet the new profile

For radiation values, the postulated normal operating dose rates are based on the assumption of 1% failed fuel and the postulated accident doses are based on the conservative assumptions and methodologies in NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-term Recommendations," NUREG-0737, "Clarification of TMI Action Plan Requirements," and NUREG-0588.

The guidance in10 CFR 50.49 requires EQ components to be refurbished, replaced, or have their qualification extended prior to reaching their aging limits as established in the St. Lucie Environmental Qualification Program aging evaluations. Therefore, although the preferred method is to demonstrate that there is enough conservatism in the EQ analyses to absorb environmental changes occurring due to plant modifications and events, there are other options available (e.g., replacement). The St. Lucie Environmental Qualification Program will be maintained through the period of extended operation.

The temperature and radiation values used for service conditions in the EQ analyses are the maximum operating values for St. Lucie. With regard to radiation, EQ is based on area radiation dose rate values for continuous operation with 1% failed fuel. This is conservative because St. Lucie Units 1 and 2 have never operated with more than 0.1% fuel clad leaks, and have had a number of fuel cycles with no fuel clad leaks.

Containment area radiation levels are monitored continuously by eight (four per Unit) radiation monitors located in various locations throughout each Containment (note that these monitors are in addition to the safety-related high range radiation, particulate, and gas monitors). The Unit 1 UFSAR Chapter 12.1.4, and Unit 2 UFSAR Chapter 12.3.4, describe the Area Radiation Monitoring Systems. High radiation activity in any of these monitored locations is indicated, recorded and alarmed in the appropriate control room. To ensure that monitored radiation levels are bounding for the service environment for EQ components, the high alarm setpoint of the monitors is much less than the values used for normal containment dose rates in EQ calculations.

For the balance of the plant, the Area Radiation Monitoring Systems have 26 monitors on Unit 1 and 33 monitors on Unit 2, located throughout the Auxiliary and Fuel Handling Buildings, that are indicated, recorded, and alarmed in the appropriate control room. In addition, the Health Physics radiation monitoring program surveys areas outside the Containments at least monthly, and in some cases daily or weekly. This combined with the dose calculation assumption of 1% failed fuel (St. Lucie Units 1 and 2 have never had more than 0.1% failed fuel), and the fact that accident doses are typically 10 to 100 times greater than normal operating doses, assures that any changes in the normal dose will be identified long before a component exceeds its qualified dose.

St. Lucie Units 1 and 2 are required by 3.6.1.5 of their respective Technical Specifications to assure that the average air temperature inside the Containments does not exceed 120^{o}F. This is accomplished by recording the average of three of the four containment fan cooler inlet temperature detectors for Unit 1 and the two containment air temperature detectors for Unit 2 daily. Per the plant operating procedures, the recorded average temperature is required to be less than or equal to 115^{o}F. It should be noted that the average of three of the four containment fan cooler inlet temperature detectors may be used for Unit 2 if one of the containment air temperature detectors is out of service. Containment air temperature detectors are also installed on Unit 1 and are used for monitoring temperature in response to a containment pressure pre-trip alarm.

The detectors associated with the containment fan coolers for Unit 1 are located on the 45- and 62-foot elevations in Containment. The Unit 2 detectors are located at the 70-foot elevation. Thus the Unit 1 detectors are at the same level as the EQ components inside Containment. Since the aging calculations for Unit 1 assume a continuous temperature of 120^{o}F, take into account self-heating, and do not credit seasonal and shutdown temperature reductions, significant margin exists to ensure that the qualified life of the EQ components inside containment is not exceeded. The Unit 2 detectors are higher than the EQ components inside Containment. This, in combination with the items mentioned for Unit 1, permits a continuous temperature of 115^{o}F to be used for the Unit 2 in-Containment EQ component aging calculations and still assures that the qualified life of a component will not be exceeded.

Outside the Containments, the qualified life calculations are based on a continuous maximum temperature of 104^{o}F. The only defined harsh temperature areas in the Environmental Qualification Program outside of the Containments are located in outdoor areas (i.e., Main Steam Trestles). Components on the Environmental Qualification List that are located in the Auxiliary Buildings are only required to be qualified for harsh radiation environments. Per Unit 1 UFSAR Table 2.3-10 and Unit 2 UFSAR Tables 2.3-37 and 2.3-38, the annual mean temperature for the site is between 72.5^{o}F and 75^{o}F. This 29^{o}F difference in temperature indicates that the qualified life based on actual average temperature is more than double the life used by the St Lucie EQ analyses. This, combined with feedback through FPL's Corrective Action Program from operator walkdowns as part of their daily rounds, and maintenance and system engineering personnel assures that changes in the plant environment or unexpected degradation of an EQ component is identified prior to the component exceeding its qualified life. Components included in the St. Lucie Environmental Qualification Program have been evaluated to determine if existing EQ aging analyses remain valid for the period of extended operation. Qualification for the license renewal period will be treated the same as for components currently included in the Environmental Qualification Program.

The St. Lucie Environmental Qualification Program manages component thermal, radiation, and wear cycle aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components must be refurbished, replaced, or their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAAs for license renewal.

4.4.1 ELECTRICAL AND I&C COMPONENT ENVIRONMENTAL QUALIFICATION ANALYSES

Age-related service conditions that are applicable to EQ components (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current EQ analyses were bounding. Temperature and radiation values assumed for service conditions in the EQ analyses are the maximum required operating values for St. Lucie Units 1 and 2. The following paragraphs describe the thermal, radiation, and wear cycle aging effects that were evaluated.

THERMAL CONSIDERATIONS - The component qualification temperatures were calculated for 60 years using the Arrhenius method, as described in EPRI NP-1558, "A Review of Equipment Aging Theory and Technology" [Reference 4.4-3]. The St. Lucie Units 1 and 2 Technical Specifications temperature limit for inside each 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. For areas outside Containment the aging calculations are based on a temperature of 104°F.

For conservatism, a temperature rise of 18°F was added to the maximum design operating temperature for power cables and penetrations to account for ohmic heating during normal operations. This results in maximum required operating temperatures of 138°F inside Containment and 122°F outside Containment for these power cables and penetrations. A review of EQ motor applications on both Units identified two applications that have a heat rise greater than 18°F. These two applications are the Unit 1 charging pump and Unit 1 containment fan cooler motors. In these applications the motors are normally running to support plant operation. A review of the qualification for the cables associated with the Unit 1 charging pump and Unit 1 containment fan cooler motors shows that the specific power cables are qualified for the higher temperature rise (see Subsections 4.4.1.27, 4.4.1.31, 4.4.1.32, and 4.4.1.33). If the component qualification temperature bounded its maximum required operating temperatures, then no additional evaluation was required.

In connection with plant modifications, some new EQ components that will not experience 60 years of thermal aging by the end of the license renewal period were installed at St. Lucie. In these cases, credit may be taken for less than 60 years of aging. This applies to three EQ analyses; EGS Grayboot connectors, Bisco Locaseals, and United Controls International Silicone Tape, described in Subsections 4.4.1.15, 4.4.1.25 and 4.4.1.51, respectively.

RADIATION CONSIDERATIONS - The St. Lucie Environmental Qualification Program has established bounding radiation dose qualification values for all EQ components. These bounding radiation dose values were determined by component vendors through testing. To verify that the bounding radiation values are acceptable for the period of extended operation, 60-year integrated dose values were determined and then compared to the bounding 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.

The EQ component 60-year total integrated doses inside the Containments are predominately $2x10^7$ rads for Unit 1 and $1.61x10^7$ rads for Unit 2. Some components may have different total integrated doses based on the location of the component and/or the required operating time of the component during and following design basis accidents. Radiation zone maps provide the 60-year normal operating dose and the 1 day, 30 day, and 1 year design basis accident doses. The total integrated dose is determined by adding the 60-year normal dose to the appropriate accident dose (based on required post accident operating time) for the specific location of the component.

WEAR CYCLE CONSIDERATIONS - 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 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 Limitorque performed in their valve operator EQ testing and significantly less than the 35,000 to 50,000 cycles that a continuous duty motor is capable of withstanding. Normally energized motors would be tested even less frequently than the standby motors and most likely will be limited by their thermal qualified life before they exceed their cycle life.

Depending on the application, solenoid valves can be cycled significantly more often than motors. This is why 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 the period of extended operation.

The values for margin identified in Section 6.3.1.5 of Institute of Electrical and Electronic Engineers (IEEE) 323-1974 were used as criteria in the St. Lucie Environmental Qualification Program. The only regular exception to the IEEE 323-1974 margins was for radiation. As identified in Item 1.4 of NUREG-0588, additional margin need not be added to the radiation parameters if the methods identified in Appendix D of NUREG-0588 are utilized. The methods used to determine the St. Lucie radiation parameters are consistent with the Appendix D methodology. Hence, the radiation margins required by Section 6.3.1.5 of IEEE 323-1974 are not necessary. Accordingly, margin is adequately addressed in the St. Lucie Environmental Qualification Program.

The following Subsections (4.4.1.1 through 4.4.1.51) provide a description for each of the EQ analyses for the period of extended operation.

4.4.1.1 ALPHA WIRE AND CABLE

Alpha wire and cable is used as Type "J" thermocouple extension wire in outside Containment applications at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Alpha wire and cable used as Type "J" thermocouple extension wire shows the cables are qualified for greater than 60 years of service at a temperature of 104°F. These cables have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Alpha wire and cable used as Type "J" thermocouple extension wire shows the cables are qualified for 6.4×10^6 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is 2.61×10^5 rads.

CONCLUSION

Alpha wire and cable used as Type "J" thermocouple extension wire is qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.2 AMERACE TERMINAL BLOCKS

The Amerace terminal blocks are located outside Containment at St. Lucie Units 1 and 2 for providing terminations between the field cables and electrical devices in the Steam Trestle Areas.

THERMAL ANALYSIS

The qualified life analysis for Amerace terminal blocks shows that the terminal blocks are qualified for greater than 60 years at a temperature of 104°F. The terminal blocks have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Amerace terminal blocks shows the terminals blocks are qualified for 2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these terminal blocks are 1.14×10^7 rads for St. Lucie Unit 1, and 4.2×10^2 rads for St. Lucie Unit 2.

CONCLUSION

Amerace terminal blocks are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.3 ANCHOR DARLING VALVE ACTUATORS

The Anchor Darling valve actuators are located in the Steam Trestle Areas outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for the Anchor Darling valve actuators shows that the actuators are qualified for greater than 60 years at a temperature of 104°F. These valve actuators have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for components of the Anchor Darling valve actuators shows the actuators are qualified for $1x10^4$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these valve actuators is $7.7x10^2$ rads.

CONCLUSION

Anchor Darling valve actuators are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.4 ASCO NORMALLY DE-ENERGIZED SOLENIOD VALVES; MODELS 206-381 AND NP-8320

Normally de-energized ASCO 206-381 solenoid valves are located inside and outside Containment on Unit 2 and inside Containment only on Unit 1. No normally de-energized ASCO NP-8320 solenoid valves are currently installed; however, the ASCO NP-8320 solenoid valve has been environmentally qualified for installation both inside and outside Containment on St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for normally de-energized ASCO 206-381 and NP-8320 solenoid valves shows the solenoid valves are qualified for greater than 60 years of service at temperatures of 120°F for solenoid valves inside Containment and 104°F for solenoid valves outside Containment. These solenoid valves have maximum required operating temperatures of 120°F inside Containment and 104°F outside Containment.

RADIATION ANALYSIS

The qualified life analysis for normally de-energized ASCO 206-381 and NP-8320 solenoid valves shows the solenoid valves are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these solenoid valves are $1.12x10^6$ rads for St. Lucie Unit 1, and $2.29x10^6$ rads for St. Lucie Unit 2.

WEAR/CYCLES

The qualified life analysis for normally de-energized ASCO 206-381 and NP-8320 solenoid valves shows the solenoid valves are qualified for 40,000 cycles. The maximum projected usage for these solenoid valves is less than 1000 cycles.

CONCLUSION

ASCO 206-381 and NP-8320 solenoid valves are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.5 ASCO NORMALLY DE-ENERGIZED SOLENOID VALVES; MODELS NP-8316, NP-8321, AND NP-8344

Normally de-energized ASCO NP-8316, NP-8321, and NP-8344 solenoid valves are located in locations both inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for normally de-energized ASCO NP-8316, NP-8321, and NP-8344 solenoid valves shows the solenoid valves are qualified for greater than 60 years of service at temperatures of 120°F for solenoid valves inside Containment and 104°F for solenoid valves outside Containment. These solenoid valves have maximum required operating temperatures of 120°F inside Containment and 104°F outside Containment.

RADIATION ANALYSIS

The qualified life analysis for normally de-energized ASCO NP-8316, NP-8321, and NP-8344 solenoid valves shows the solenoid valves are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these solenoid valves are $2.22x10^6$ rads for St. Lucie Unit 1, and $1.78x10^6$ rads for St. Lucie Unit 2.

WEAR/CYCLES

The qualified life analysis for normally de-energized ASCO NP-8316, NP-8321, and NP-8344 solenoid valves shows the solenoid valves are qualified for 40,000 cycles. The maximum projected usage for these solenoid valves is less than 1000 cycles.

CONCLUSION

Normally de-energized ASCO NP-8316, NP-8321, and NP-8344 solenoid valves are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.6 BOSTON INSULATED WIRE CABLES

The Boston Insulated Wire cables are used for instrumentation circuits inside and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Boston Insulated Wire cables shows the cables are qualified for greater than 60 years of service at a temperature of 120°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Boston Insulated Wire cables used inside Containment shows the cables are qualified for 1.8×10^{8} rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is 4.22×10^{6} rads.

The qualified life analysis for Boston Insulated Wire cables used outside Containment shows the cables are qualified for 5×10^{5} rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is 1.1×10^{5} rads.

CONCLUSION

Boston Insulated Wire cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.7 CERRO (ROCKBESTOS) CABLES

The Rockbestos cables with XLPE insulation are installed in instrumentation, control, and power applications both inside and outside Containment at St. Lucie Units 1 and 2.

INSTRUMENTATION AND CONTROL CABLES

THERMAL ANALYSIS

The qualified life analysis for Rockbestos I&C cables shows the cables are qualified for greater than 60 years of service at temperatures of 147°F for St. Lucie Unit 1 and 190°F for St. Lucie Unit 2. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Rockbestos I&C cables shows the cables are qualified for $5x10^7$ rads to $2x10^8$ rads for St. Lucie Unit 1, and $2x10^8$ rads for St. Lucie Unit 2. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Rockbestos I&C cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10C FR 54.21(c)(1)(ii).

POWER CABLES

THERMAL ANALYSIS

The qualified life analysis for Rockbestos power cables shows the cables are qualified for greater than 60 years of service at a temperature of 190°F. These cables have a maximum required operating temperature of 138°F.

RADIATION ANALYSIS

The qualified life analysis for Rockbestos power cables shows the cables are qualified for $5x10^7$ rads to $2x10^8$ rads for St. Lucie Unit 1, and $2x10^8$ rads for St. Lucie Unit 2. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads for St. Lucie Unit 1 and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Rockbestos power cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.8 CERRO (ROCKBESTOS) COAXIAL/TRIAXIAL CABLES

The Rockbestos coaxial and triaxial cables are located inside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Rockbestos coaxial and triaxial cables shows the cables are qualified for greater than 60 years of service at a temperature of 149°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Rockbestos coaxial and triaxial cables shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is $1.61x10^7$ rads.

CONCLUSION

Rockbestos coaxial and triaxial cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.9 COMBUSTION ENGINEERING MINERAL INSULATED CABLES AND CONNECTORS

The Combustion Engineering Mineral Insulated cables with Litton, Whittaker, and ERD connectors are located inside Containment at St. Lucie Units 1 and 2.

COMBUSTION ENGINEERING MINERAL INSULATED CABLE WITH LITTON (HJTC) CONNECTORS

THERMAL ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Litton (HJTC) connectors shows the cables and connectors are qualified for greater than 60 years of service at a temperature of 150°F. These cables and connectors have a maximum required operating temperature of 150°F per Combustion Engineering.

RADIATION ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Litton (HJTC) connectors shows the cables and connectors are qualified for $5.5x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables and connectors are $1.5x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Combustion Engineering Mineral Insulated cables with Litton (HJTC) connectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

COMBUSTION ENGINEERING MINERAL INSULATED CABLE WITH LITTON (CET) CONNECTORS

THERMAL ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Litton (CET) connectors shows the cables and connectors are qualified for greater than 60 years of service at a temperature of 150°F. These cables and connectors have a maximum required operating temperature of 150°F per Combustion Engineering.

RADIATION ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Litton (CET) connectors shows the cables and connectors are qualified for $2.07x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables and connectors are $1.5x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Combustion Engineering Mineral Insulated cables with Litton (CET) connectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

COMBUSTION ENGINEERING MINERAL INSULATED CABLE WITH WHITTAKER CONNECTORS

THERMAL ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Whittaker connectors shows the cables and connectors are qualified for greater than 60 years of service at a temperature of 150°F. These cables and connectors have a maximum required operating temperature of 150°F per Combustion Engineering.

RADIATION ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with Whittaker connectors shows the cables and connectors are qualified for 2.2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables and connectors are 1.5×10^7 rads for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Combustion Engineering Mineral Insulated cables with Whittaker connectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

COMBUSTION ENGINEERING MINERAL INSULATED CABLE WITH ERD/LITTON CONNECTORS

THERMAL ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with ERD/Litton connectors shows the cables and connectors are qualified for greater than 60 years of service at a temperature of 140°F. These cables and connectors have a maximum required operating temperature of 140°F per Combustion Engineering.

RADIATION ANALYSIS

The qualified life analysis for Combustion Engineering Mineral Insulated cables with ERD/Litton connectors shows the cables and connectors are qualified for 2.1×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables and connectors is 1.5×10^7 rads.

CONCLUSION

Combustion Engineering Mineral Insulated cables with ERD/Litton connectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.10 CONAX CONDUIT SEALS

The Conax electric conductor seal assemblies are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Conax electric conductor seal assemblies shows the assemblies are qualified for greater than 60 years of service at a temperature of 194°F. These assemblies have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Conax electric conductor seal assemblies shows the assemblies are qualified for 1.4×10^9 rads (beta and gamma). The maximum projected post accident plus 60-year normal operation radiation doses for these assemblies are 2×10^7 for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Conax electric conductor seal assemblies are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.11 CONAX PENETRATIONS

The Conax electrical penetrations are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Conax electrical penetrations shows the penetrations are qualified for greater than 60 years of service at a temperature of 194°F. These penetrations have maximum required operating temperatures of 138°F for power applications and 120°F for I&C applications.

RADIATION ANALYSIS

The qualified life analysis for Conax electrical penetrations shows the penetrations are qualified for 1.1×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these penetrations are 2×10^7 for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Conax electrical penetrations are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.12 CONAX THERMOCOUPLES

The Conax thermocouples are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Conax thermocouples shows the thermocouples are qualified for greater than 60 years of service at a temperature of 120°F. These thermocouples have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Conax thermocouples shows the thermocouples are qualified for 2.27×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these thermocouples are 2×10^7 rads for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Conax thermocouples are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.13 CONTINENTAL CABLES

The Continental cables are used as thermocouple extension wires both inside and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Continental cables shows the cables are qualified for greater than 60 years of service at a temperature of 125°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Continental cables shows the cables are qualified for $1x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is $2x10^7$ rads.

CONCLUSION

Continental cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.14 CVI HEATERS

The CVI heaters are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for CVI heaters shows the heaters are qualified for greater than 60 years of service at a temperature of 107°F. These heaters have a maximum required operating temperature of 107°F.

RADIATION ANALYSIS

The qualified life analysis for CVI heaters shows the heaters are qualified for 6.4×10^6 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these heaters is 2.6×10^5 rads.

CONCLUSION

CVI heaters are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.15 EGS GRAYBOOT CONNECTORS

The EGS Grayboot connectors are installed both inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The EGS Grayboot connectors were first installed at St. Lucie Units 1 and 2 in 1995. The qualified life analysis for EGS Grayboot connectors shows the connectors are qualified for greater than 47.4 years at a temperature of 130°F. These connectors have a maximum required operating temperature of 130°F.

RADIATION ANALYSIS

The qualified life analysis for EGS Grayboot connectors shows the connectors are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these connectors is $5.25x10^7$ rads.

CONCLUSION

Since EGS Grayboot connectors were not used at St. Lucie Units 1 and 2 until 1995, a qualified life of 47.4 years provides qualification through the end of the period of extended operation. EGS Grayboot connectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.16 FLUID CONTROL INCORPORATED LEVEL SENSORS

Fluid Control Incorporated level sensors are located inside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Fluid Control Incorporated level sensors shows the sensors are qualified for greater than 60 years of service at a temperature of 120°F. These sensors have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Fluid Control Incorporated level sensors shows the sensors are qualified for 1×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these sensors is 8.65×10^6 rads.

CONCLUSION

Fluid Control Incorporated level sensors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.17 GENERAL ATOMIC RADIATION MONITORS

The General Atomic radiation monitor detectors are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for General Atomic radiation monitor detectors shows the detectors are composed of inorganic materials and are not susceptible to thermal degradation. At St. Lucie Unit 2, two associated components are susceptible to thermal degradation, a Teflon connector and a silicon rubber seal. The qualified life analysis for these components shows the Unit 2 detectors and associated components are qualified for greater than 92 years of service at a temperature of 120°F. The Unit 2 detectors and associated components have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for General Atomic radiation monitor detectors shows the detectors are composed of inorganic materials and are not susceptible to radiation degradation. At St. Lucie Unit 2, two associated components are susceptible to radiation aging, a Teflon connector and a silicon rubber seal. The qualified life analysis for these components shows the Unit 2 detectors and associated components are qualified for 2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for the Unit 2 detectors and associated components is 1.61×10^7 rads.

CONCLUSION

General Atomic radiation monitor detectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.18 GENERAL CABLE CABLES

General Cable instrumentation cables are located inside and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for General Cable instrumentation cables shows the cables are qualified for greater than 60 years of service at a temperature of 121°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for General Cable instrumentation cables shows the cables are qualified for 5×10^7 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is 5.15×10^6 rads.

CONCLUSION

General Cable instrumentation cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.19 GENERAL ELECTRIC CABLES

The General Electric Vulkene cables are installed as jumper wire for the main steam isolation valve limit switches in the Steam Trestle Area outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for General Electric Vulkene cables shows the cables are qualified for greater than 60 years of service at a temperature of 150°F. These cables have a maximum required operating temperature of 150°F.

RADIATION ANALYSIS

The qualified life analysis for General Electric Vulkene cables shows the cables are qualified for $2.2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is less than $1x10^3$ rads.

CONCLUSION

General Electric Vulkene cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.20 GENERAL ELECTRIC HIGH PRESSURE SAFETY INJECTION (UNIT 1) AND AUXILIARY FEEDWATER PUMP MOTORS

The General Electric High Pressure Safety Injection (Unit 1) and Auxiliary Feedwater (Units 1 and 2) pump motors are located outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for General Electric High Pressure Safety Injection (Unit 1) and Auxiliary Feedwater (Units 1 and 2) pump motors shows the motors are qualified for greater than 60 years of service at an ambient temperature of 104°F. This qualified life is the life remaining after subtracting the motor run time for maintenance and periodic testing during the 60-year plant lifetime at a motor operating temperature of 266°F. The effect of the motor space heater during motor inactive periods has also been subtracted from the motor qualified life. These motors are located in an area where the ambient temperature is 104°F.

RADIATION ANALYSIS

The qualified life analysis for General Electric High Pressure Safety Injection (Unit 1) and Auxiliary Feedwater (Units 1 and 2) pump motors shows the motors are qualified for 1×10^7 rads for St. Lucie Unit 1, and 1×10^6 rads for St. Lucie Unit 2. The maximum projected post accident plus 60-year normal operation radiation doses for these motors are less than 1×10^3 rads for the auxiliary feedwater pump motors, and 3.25×10^5 rads for the high pressure safety injection pump motors.

CONCLUSION

General Electric High Pressure Safety Injection (Unit 1) and Auxiliary Feedwater (Units 1 and 2) pump motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.21 GENERAL ELECTRIC HIGH PRESSURE SAFETY INJECTION (UNIT 2) PUMP MOTORS

The General Electric High Pressure Safety Injection (Unit 2) pump motors are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for General Electric High Pressure Safety Injection (Unit 2) pump motors shows the motors are qualified for greater than 60 years at an ambient temperature of 104°F. This qualified life is the life remaining after subtracting the motor run time for maintenance and periodic testing during the 60-year plant lifetime at a motor operating temperature of 230°F. The effect of the motor space heater during motor inactive periods has also been subtracted from the motor qualified life. These motors are located in an area where the ambient temperature is 104°F.

RADIATION ANALYSIS

The qualified life analysis for General Electric High Pressure Safety Injection (Unit 2) pump motors shows the motors are qualified for $1x10^6$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is $8.15x10^5$ rads.

CONCLUSION

General Electric High Pressure Safety Injection (Unit 2) pump motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.22 GENERAL ELECTRIC TERMINAL BLOCKS

General Electric terminal blocks are located outside Containment at St. Lucie Units 1 and 2. St. Lucie Unit 1 has General Electric type EB-5, CR-2940 and CR-151 terminal blocks installed. St. Lucie Unit 2 has General Electric type EB-5 and EB-25 terminal blocks installed.

THERMAL ANALYSIS

The qualified life analysis for General Electric terminal blocks shows the terminal blocks are qualified for greater than 60 years of service at a temperature of 104°F. These terminal blocks have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for General Electric St. Lucie Unit 1 terminal blocks shows the terminal blocks are qualified for 1.2×10^7 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these terminal blocks is 1×10^7 rads.

The qualified life analysis for General Electric St. Lucie Unit 2 terminal blocks shows the terminal blocks are qualified for 2.1×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these terminal blocks is 5.25×10^7 rads.

CONCLUSION

General Electric terminal blocks are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.23 GORDON THERMOCOUPLES

The Gordon thermocouples are located outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Gordon thermocouples shows that the thermocouples are qualified for greater than 60 years at a temperature of 104°F. These thermocouples have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Gordon thermocouples shows the thermocouples are qualified for 1.06×10^7 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these thermocouples is 3.7×10^5 rads.

CONCLUSION

Gordon thermocouples are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.24 GULF GENERAL ATOMIC ELECTRICAL PENETRATIONS

The Gulf General Atomic electrical penetrations are in use at St. Lucie Unit 1 for low voltage power, control, and instrumentation circuits.

THERMAL ANALYSIS

The qualified life analysis for Gulf General Atomic electrical penetrations shows that the penetrations are qualified for greater than 60 years at a temperature of 140°F. These penetrations have a maximum required operating temperature of 138°F.

RADIATION ANALYSIS

The qualified life analysis for Gulf General Atomic electrical penetrations shows the penetrations are qualified for $5.5x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these penetrations is $2x10^7$ rads.

CONCLUSION

Gulf General Atomic electrical penetrations are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.25 IMO INDUSTRIES LEVEL SENSORS

The IMO Industries level sensors are located inside Containment at St. Lucie Unit 1. The level sensors utilize Bisco Locaseals to provide a watertight connection for the system conduits that are below flood level.

THERMAL ANALYSIS

The qualified life analysis for IMO Industries level sensors shows that the sensors are qualified for greater than 60 years at a temperature of 120°F. The Bisco Locaseal material has been demonstrated to have a qualified life of 56 years at 120°F. These sensors and seals have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for IMO Industries level sensors shows the sensors are qualified for 1.16×10^8 rads. The Bisco Locaseal material is qualified for 2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these sensors and seals is 9.25×10^6 rads.

CONCLUSION

Since the Bisco Locaseal material was not used at St. Lucie Unit 1 until 1991, the IMO Industries level sensors and Bisco Locaseals are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.26 INDEECO HEATERS

The Indeeco heaters are located outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Indeeco heaters shows that the heaters are qualified for greater than 60 years at a temperature of 104°F. These heaters are not used except following a design basis event. These heaters have a normal operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Indeeco heaters shows the heaters are qualified for $1x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these heaters is $3.7x10^5$ rads.

CONCLUSION

Indeeco heaters are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.27 KERITE CABLES (FR, FR2, AND HTK INSULATION)

The Kerite cables with FR, FR2, and HTK insulation are located inside and outside Containment at St. Lucie Units 1 and 2 in low and medium voltage power, control, and instrumentation circuits.

THERMAL ANALYSIS

The qualified life analysis for Kerite cables with FR, FR2, and HTK insulation shows that the cables are qualified for greater than 60 years at a temperature of 194°F. These cables have a maximum required operating temperature of 145°F (Unit 1 containment fan cooler motors).

RADIATION ANALYSIS

The qualified life analysis for Kerite cables with FR, FR2, and HTK insulation shows the cables are qualified for $5x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Kerite cables with FR, FR2, and HTK insulation are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.28 LIMITORQUE VALVE OPERATORS

The Limitorque operators with Class B insulation are located outside Containment, and Limitorque operators with Class RH insulation are located inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Limitorque actuators with Class B and Class RH insulation shows that the actuators are qualified for greater than 60 years at temperatures of 120°F for St. Lucie Unit 1 and 115°F for St. Lucie Unit 2. These actuators have maximum required operating temperatures of 120°F for St. Lucie Unit 1 and 115°F for St. Lucie Unit 2.

RADIATION ANALYSIS

The qualified life analysis for Limitorque actuators with Class B insulation shows the actuators are qualified for $2x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these actuators are $7.9x10^5$ rads for St. Lucie Unit 1, and $1.8x10^6$ rads for St. Lucie Unit 2.

The qualified life analysis for Limitorque actuators with Class RH insulation shows the actuators are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these actuators are $9.25x10^6$ rads for St. Lucie Unit 1, and $6.85x10^6$ rads for St. Lucie Unit 2.

CONCLUSION

Limitorque actuators with Class B and Class RH insulation are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.29 MAGNETROL LEVEL SWITCH

The Magnetrol level switches are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Magnetrol level switches shows that the switches are qualified for greater than 60 years at a temperature of 104°F. These switches have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Magnetrol level switches shows the switches are qualified for 2.5×10^7 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these switches is 8.15×10^5 rads.

CONCLUSION

Magnetrol level switches are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.30 MICRO SWITCH LIMIT SWITCH

The Micro Switch limit switches are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Micro Switch limit switches shows that the switches are qualified for greater than 60 years at a temperature of 104°F. These switches have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for Micro Switch limit switches shows the switches are qualified for $1x10^7$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these switches is $8.15x10^5$ rads.

CONCLUSION

Micro Switch limit switches are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.31 OKONITE CABLES (EPR INSULATION)

Okonite control cables with EPR insulation are located inside and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Okonite control cable with EPR insulation shows that the cables are qualified for greater than 60 years at a temperature of 145°F inside Containment and 122°F outside Containment. These cables have maximum required operating temperatures of 145°F (Unit 1 containment fan cooler motors) inside Containment and 122°F outside Containment.

RADIATION ANALYSIS

The qualified life analysis for Okonite control cable with EPR insulation shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads inside Containment, and $5.25x10^7$ rads outside Containment.

CONCLUSION

Okonite control cables with EPR insulation are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.32 OKONITE CABLES (X-OLENE FMR INSULATION)

Okonite power, control, and low signal level cables with X-Olene FMR insulation are located inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Okonite power, control, and low signal level cables with X-Olene FMR insulation shows that the cables are qualified for greater than 60 years at a temperature of 138°F inside Containment and 134.3°F outside Containment. These cables have maximum required operating temperatures of 138°F inside Containment and 134.3 °F (Unit 1 containment fan cooler motors) outside Containment.

RADIATION ANALYSIS

The qualified life analysis for Okonite power, control, and low signal level cables with X-Olene FMR insulation shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads inside the St. Lucie Unit 1 Containment, $1.61x10^7$ rads inside the St. Lucie Unit 2 Containment, and $5.25x10^7$ rads outside Containment.

CONCLUSION

Okonite power, control, and low signal level cables with X-Olene FMR insulation are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.33 RAYCHEM CABLES

The Raychem cables with XLPE (FLAMTROL) insulation is located inside and outside Containment at St. Lucie Units 1 and 2. The St. Lucie Unit 1 cables are used in various power, control, and instrumentation circuits. The St. Lucie Unit 2 cables are used as control wiring in Limitorque motor operators.

THERMAL ANALYSIS

The qualified life analysis for Raychem cables with XLPE (FLAMTROL) insulation utilized for jumper wire applications in Units 1 and 2 shows that the cables are qualified for greater than 60 years at a temperature of 125°F for jumper wire applications inside Containment. These cables have a maximum required operating temperature of 125°F inside Containment.

The qualified life analysis for Raychem cables with XLPE (FLAMTROL) insulation shows the cables are qualified for greater than 60 years with a conductor temperature of 167.9°F. These cables have a maximum required operating temperature of 156°F (Unit 1 charging pump motors).

RADIATION ANALYSIS

The qualified life analysis for Raychem cables with XLPE (FLAMTROL) insulation shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $5.25x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Raychem cables with XLPE (FLAMTROL) insulation are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.34 RAYCHEM SPLICES

The Raychem heat shrink sleeving is located both inside and outside Containment at St. Lucie Units 1 and 2. Raychem heat shrink sleeving includes the following types: WCSF-N, WCSF-050-N, WCSF-050-U, NPKV, NHVT, NMCK, cable breakouts, and end caps.

THERMAL ANALYSIS

The qualified life analysis for Raychem heat shrink sleeving shows that the sleeving materials are qualified for greater than 60 years at a temperature of 185°F (120°F plus 65°F self-heating). The maximum design operating temperature of the sleeving materials would be much less than 185°F due to conservative plant designs, equipment out-of-service time, equipment redundancy, and because the sleeving insulation material is not in direct contact with the cable conductor.

RADIATION ANALYSIS

The qualified life analysis for Raychem heat shrink sleeving shows the sleeving materials are qualified for $2x10^8$ rads to $2.2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these sleeving materials are $2x10^7$ rads inside the St. Lucie Unit 1 Containment, $1.61x10^7$ rads inside the St. Lucie Unit 2 Containment, and $5.25x10^7$ rads outside Containment.

CONCLUSION

Raychem heat shrink sleeving is qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.35 RdF RESISTANCE TEMPERATURE DETECTORS

The RdF resistance temperature detectors are located at St. Lucie Unit 2 outside Containment.

THERMAL ANALYSIS

The qualified life analysis for RdF resistance temperature detectors located outside Containment shows that the detectors are qualified for greater than 89 years at a temperature of 104°F. These detectors have a maximum required operating temperature of 104°F.

RADIATION ANALYSIS

The qualified life analysis for RdF resistance temperature detectors located outside Containment shows the detectors are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these detectors is $1.78x10^6$ rads outside Containment.

CONCLUSION

RdF resistance temperature detectors outside Containment are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.36 RELIANCE ELECTRIC CONTAINMENT FAN COOLER MOTORS

The Reliance Electric containment fan cooler motors are located inside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Reliance Electric containment fan cooler motors shows the motors are qualified for greater than 60 years at a maximum design temperature of 215.4°F. These motors have a maximum required operating temperature of 215.4°F.

RADIATION ANALYSIS

The qualified life analysis for Reliance Electric containment fan cooler motors shows the motors are qualified for $8x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is $1.61x10^7$ rads.

CONCLUSION

Reliance Electric containment fan cooler motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.37 ROME CABLES

The Rome cables are located inside and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Rome cables shows the cables are qualified for greater than 60 years of service at a temperature of 123°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Rome cables shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these cables is $5.25x10^7$ rads.

CONCLUSION

Rome cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.38 SIEMENS ALLIS CONTAINMENT SPRAY PUMP MOTORS

The Siemens Allis containment spray pump motors are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for the Siemens Allis containment spray pump motors shows that the motors are qualified for greater than 60 years at an ambient temperature of 104°F based on an assumption of 15 years of motor operating time at a temperature of 250.3°F during the plant lifetime.

RADIATION ANALYSIS

The qualified life analysis for Siemens Allis containment spray pump motors shows the motors are qualified for 2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is 8.15×10^7 rads.

CONCLUSION

Siemens Allis containment spray pump motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.39 TARGET ROCK NORMALLY DE-ENERGIZED SOLENOID VALVES; SERIES 80B

Normally de-energized Target Rock Model 80B solenoid valves are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for normally de-energized Target Rock Model 80B solenoid valves shows the solenoid valves are qualified for greater than 60 years of service at a temperature of 120°F. These solenoid valves have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for normally de-energized Target Rock Model 80B solenoid valves shows the solenoid valves are qualified for 1.35×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these solenoid valves are 2×10^7 rads for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Normally de-energized Target Rock Model 80B solenoid valves are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.40 TARGET ROCK NORMALLY DE-ENERGIZED SOLENOID VALVES; SERIES 74Q, 76R, 78E, 84V, 89Q, AND 98K

Normally de-energized Target Rock Model 74Q and 89Q solenoid valves are located inside and outside Containment at St. Lucie Unit 1. Normally de-energized Target Rock Models 74Q, 76R, 78E, 84V, and 98K solenoid valves are located inside and outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for normally de-energized Target Rock Models 74Q, 76R, 78E, 84V, 89Q, and 98K solenoid valves shows the solenoid valves are qualified for greater than 60 years of service at a temperature of 120°F. These solenoid valves have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for normally de-energized Models 74Q, 76R, 78E, 84V, 89Q, and 98K solenoid valves shows the solenoid valves are qualified for 1.35×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these solenoid valves are 2×10^7 rads for St. Lucie Unit 1, and 1.61×10^7 rads for St. Lucie Unit 2.

CONCLUSION

Normally de-energized Models 74Q, 76R, 78E, 84V, 89Q, and 98K solenoid valves are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.41 TEC ACOUSTIC MONITORS - ACCELEROMETER AND CABLE ASSEMBLY

The TEC Acoustic Flow Monitoring Systems are located on the pressurizer safety valves inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for TEC Acoustic Flow Monitoring Systems shows the systems are qualified for greater than 60 years of service at a temperature of 122°F. These systems have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for TEC Acoustic Flow Monitoring Systems shows the systems are qualified for $1.9x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these systems are $1.05x10^6$ rads for St. Lucie Unit 1, and $6.85x10^6$ rads for St. Lucie Unit 2.

CONCLUSION

TEC Acoustic Flow Monitoring Systems are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.42 TELEDYNE THERMATICS CABLE

The Teledyne Thermatics cables are located both inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for Teledyne Thermatics cables shows the cables are qualified for greater than 60 years of service at a temperature of 125°F. These cables have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Teledyne Thermatics cables shows the cables are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these cables are $2x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Teledyne Thermatics cables are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.43 3M TAPE SPLICES

The 3M tape splices are located outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for 3M tape splices shows the splices are qualified for greater than 60 years of service at a temperature of 122°F. These splices have a maximum required operating temperature of 122°F.

RADIATION ANALYSIS

The qualified life analysis for 3M tape splices shows the splices are qualified for 2×10^8 rads for 600V applications, and 1×10^8 rads for 4kV applications. The maximum projected post accident plus 60-year normal operation radiation dose for these splices is 5.25×10^7 rads for both 600V and 4kV applications.

CONCLUSION

The 3M tape splices are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.44 VALCOR NORMALLY DE-ENERGIZED SOLENOID VALVES

Normally de-energized Valcor solenoid valves are located inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for normally de-energized Valcor solenoid valves shows the solenoid valves are qualified for greater than 60 years of service at a temperature of 120°F. These solenoid valves have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for normally de-energized Valcor solenoid valves shows the solenoid valves are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these solenoid valves are $5.42x10^6$ rads for St. Lucie Unit 1, and $3.85x10^6$ rads for St. Lucie Unit 2.

CONCLUSION

Normally de-energized Valcor solenoid valves are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.45 WEED RESISTANCE TEMPERATURE DETECTORS

The Weed resistance temperature detectors are located inside Containment at St. Lucie Units 1 and 2 and outside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Weed resistance temperature detectors shows that the detectors are qualified for greater than 60 years at a temperature of 127°F. These detectors have a maximum required operating temperature of 127°F.

RADIATION ANALYSIS

The qualified life analysis for Weed resistance temperature detectors shows the detectors are qualified for $3.03x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these detectors are $2.45x10^7$ rads inside Containment, and $2.88x10^6$ rads outside Containment.

CONCLUSION

Weed resistance temperature detectors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.46 WESTINGHOUSE CHARGING PUMP MOTORS

The Westinghouse charging pump motors are located outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for the Westinghouse charging pump motors shows that the motors are qualified for greater than 60 years at an ambient temperature of 104°F based on an assumption of 42 percent operating duty at a temperature of 230°F for St. Lucie Unit 1, and 33.3 percent operating duty at a temperature of 237.5°F for St. Lucie Unit 2.

RADIATION ANALYSIS

The qualified life analysis for Westinghouse charging pump motors shows the motors are qualified for 1×10^6 rads for St. Lucie Unit 1 and 5×10^6 rads for St. Lucie Unit 2. The maximum projected post accident plus 60-year normal operation radiation doses for these motors are 4.45×10^5 rads for St. Lucie Unit 1, and 2.75×10^5 rads for St. Lucie Unit 2.

CONCLUSION

Westinghouse charging pump motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.47 WESTINGHOUSE CONTAINMENT FAN COOLER MOTORS

The Westinghouse containment fan cooler motors are located inside Containment at St. Lucie Unit 1.

THERMAL ANALYSIS

The qualified life analysis for Westinghouse containment fan cooler motors shows that the motors are qualified for greater than 67.8 years at a temperature of 180°F. These motors have a maximum required operating temperature of 180°F.

RADIATION ANALYSIS

The qualified life analysis for Westinghouse containment fan cooler motors shows the motors are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is $2x10^7$ rads.

CONCLUSION

Westinghouse containment fan cooler motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.48 WESTINGHOUSE HYDROGEN RECOMBINERS

The Westinghouse hydrogen recombiners are located inside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for the Westinghouse hydrogen recombiners shows that the recombiners are qualified for greater than 60 years at a temperature of 120°F. These recombiners have a maximum required operating temperature of 120°F.

RADIATION ANALYSIS

The qualified life analysis for Westinghouse hydrogen recombiners shows the recombiners are qualified for $2x10^8$ rads. The maximum projected post accident plus 60-year normal operation radiation doses for these recombiners are $1.2x10^7$ rads for St. Lucie Unit 1, and $1.61x10^7$ rads for St. Lucie Unit 2.

CONCLUSION

Westinghouse hydrogen recombiners are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.49 WESTINGHOUSE LOW PRESSURE SAFETY INJECTION PUMP MOTORS

The Westinghouse low pressure safety injection pump motors are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for the Westinghouse low pressure safety injection pump motors shows that the motors are qualified for greater than 89.09 years at an ambient temperature of 104°F based on an assumption of 25 percent operating duty at a temperature of 230°F.

RADIATION ANALYSIS

The qualified life analysis for Westinghouse low pressure safety injection pump motors shows the motors are qualified for $2x10^8$ rads for model 5010P39VSWT, and $5x10^7$ rads for model 5010P39WPI. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is $8.15x10^5$ rads.

CONCLUSION

Westinghouse low pressure safety injection pump motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.50 WESTINGHOUSE VENTILATION FAN MOTORS

The Westinghouse ventilation fan motors are located outside Containment at St. Lucie Unit 2.

THERMAL ANALYSIS

The qualified life analysis for Westinghouse ventilation fan motors shows that the motors are qualified for greater than 60 years at a temperature of 266°F. These motors have a maximum required operating temperature of 266°F.

RADIATION ANALYSIS

The qualified life analysis for Westinghouse ventilation fan motors shows the motors are qualified for 2×10^8 rads. The maximum projected post accident plus 60-year normal operation radiation dose for these motors is 2.61×10^5 rads.

CONCLUSION

Westinghouse ventilation fan motors are qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.1.51 UNITED CONTROLS INTERNATIONAL SILICONE TAPE

The United Controls International silicone tape is installed both inside and outside Containment at St. Lucie Units 1 and 2.

THERMAL ANALYSIS

The qualified life analysis for United Controls International silicone tape in control and intermittently energized power circuits applications shows that these splices are qualified for greater than 48.3 years at a temperature of 170°F. These splices have a maximum required operating temperature of 170°F.

RADIATION ANALYSIS

The qualified life analysis for United Controls International silicone tape in control and intermittently energized power circuits applications shows the splices are qualified for 5.77×10^7 rads. The maximum projected post accident plus 60-year normal operation radiation doses for these splices are 2×10^7 rads for St. Lucie Unit 1, and 5.25×10^7 rads for St. Lucie Unit 2.

CONCLUSION

United Controls International silicone tape was first used at St. Lucie Unit 1 in 1997, and at St. Lucie Unit 2 in 1999. Based on this, United Controls International silicone tape in control and intermittently energized power circuits applications is qualified for the period of extended operation based on the projection of the EQ analysis to the end of the period of extended operation per the provisions of 10 CFR 54.21(c)(1)(ii).

4.4.2 GSI-168, ENVIRONMENTAL QUALIFICATION OF ELECTRICAL COMPONENTS

NRC guidance for addressing GSI-168 for license renewal is contained in the June 2, 1998, NRC letter to NEI [Reference 4.4-4]. In this letter, the NRC states, "With respect to addressing GSI-168 for license renewal, until completion of an ongoing research program and staff evaluations, the potential issues associated with GSI-168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the Statements of Consideration is to provide a technical rationale demonstrating that the current licensing basis for EQ pursuant to 10 CFR 50.49 will be maintained in the period of extended operation. Although the Statements of Consideration also indicate that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time."

EQ evaluations of electrical components are identified as TLAAs for St. Lucie Units 1 and 2. The evaluations of these TLAAs are considered the technical rationale that the St. Lucie Units 1 and 2 CLBs will be maintained during the period of extended operation. These evaluations are provided in Section 4.4 of the St. Lucie Units 1 and 2 License Renewal Application. Consistent with the above NRC guidance, no additional information is required to address GSI-168 in a renewal application at this time.

4.4.3 REFERENCES

4.4-1 DOR Guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," U. S. Nuclear Regulatory Commission, June 1979.

4.4-2 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U. S. Nuclear Regulatory Commission, April 2001.

4.4-3 EPRI NP-1558, "A Review of Equipment Aging Theory and Technology," Electric Power Research Institute, September 1980.

4.4-4 Grimes, C. I. (NRC) letter to Walters, D. (NEI), "Guidance on Addressing GSI 168 for License Renewal," Project 690, June 2, 1998.

4.5 METAL CONTAINMENT AND PENETRATION FATIGUE

4.5.1 METAL CONTAINMENT FATIGUE

NUREG-1800 [Reference 4.5-1], Section 4.6, addresses TLAAs for metal containments. For completeness, NUREG-1800, Section 4.6 is addressed in this application, although no TLAAs exist for the St. Lucie Units 1 and 2 Containment Vessels.

The St. Lucie Units 1 and 2 Containment Vessels are fabricated from welded steel plate to provide an essentially leak-tight barrier. Design criteria applied to the steel 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 the Containment Vessels based on the applicable design codes. Additionally, a review determined that fatigue analysis is not required for the Containment Vessels for the period of extended operation based on the applicable design codes. Therefore, fatigue is not a TLAA for the St. Lucie Units 1 and 2 Containment Vessels.

4.5.2 PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I Those which must accommodate considerable thermal movements (hot penetrations)
- Type II Those which are not required to accommodate thermal movements (cold penetrations)
- Type III Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV Containment sump recirculation suction lines
- Type V Fuel transfer tubes

Type I and Type III Penetrations

The thermal fatigue design limits of the Type I and Type III containment penetration bellows are bounded by the thermal fatigue design limits of their associated piping systems. The piping systems associated with Type I and Type III penetration bellows have been evaluated in Subsections 4.3.1 and 4.3.2, and found acceptable for the period of extended operation. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

Type II and Type IV Penetrations

Type II penetrations are cold penetrations and Type IV penetrations are only used in post accident scenarios. As such, these penetrations do not require a thermal fatigue analysis. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

Type V Penetrations

Since the Units 1 and 2 fuel transfer penetrations are not subject to elevated temperatures, they are not subject to thermal fatigue and thus meet the requirements for 7000 thermal cycles. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

The analyses associated with the containment penetration bellows fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.5.3 REFERENCES

4.5-1 NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," U. S. Nuclear Regulatory Commission, April 2001.

4.6 PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

4.6.1 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed NSSSs, which included St. Lucie Units 1 and 2 [Reference 4.6-1]. The LBB analysis was performed to show that any potential leaks that develop in the Reactor Coolant System primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in the March 5, 1993, NRC letter to FPL [Reference 4.6-2], the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group (CEOG) analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of St. Lucie Units 1 and 2.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the Reactor Coolant System loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review by the NSSS supplier concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which bounds the extended period of operation. Therefore the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA (i.e., it does not involve a time-limited assumption defined by the current 40-year operating term) and no additional evaluation is required for the period of extended operation.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles discussed in Subsection 4.3.1 are consistent with those utilized in the LBB fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The Reactor Coolant System primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.2 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs.

- 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)
- Intake Structure Bridge Cranes

The St. Lucie Units 1 and 2 cranes listed above meet the criteria of CMAA-70 "Specifications for Electric Overhead Traveling Cranes," [Reference 4.6-3] as noted in the NRC NUREG-0612 safety evaluations [References 4.6-4 and 4.6-5]. Cranes designed in accordance with CMAA-70 are acceptable for at least 20,000 to 200,000 load cycles. Therefore, the St. Lucie Units 1 and 2 cranes are acceptable for at least 20,000 load cycles.

The St. Lucie 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. At St. Lucie, the Unit 2 spent fuel handling machine is bounding for load cycle analysis.

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 three-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 ten-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 St. Lucie cranes within the license renewal scope, all St. Lucie 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 lives are related to load lifts (fatigue life design per CMAA-70), the crane gearing and shafting are also adequate for the period of extended operation.

Crane fatigue life and structural integrity have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3 UNIT 1 CORE SUPPORT BARREL REPAIR

TLAAs were identified for the St. Lucie Unit 1 reactor vessel internals core support barrel (CSB) repair.

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 and the CSB was repaired at the thermal shield support lug locations. Four lugs were separated from the CSB and through-wall cracks were adjacent to some damaged lug areas. Through-wall cracks were arrested with crack arrestor holes, non-through-wall cracks were machined out, and lug tear out areas were machined and patched as necessary. The crack arrestor holes were sealed by inserting expandable plugs.

Analysis of the CSB repair method was performed by the NSSS supplier to demonstrate 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.

A post-repair inspection of the CSB lug area repairs was performed, in 1984, to verify proper installation of the plugs and provide a baseline for comparison of data obtained during future inspections. In accordance with commitments to the NRC [Reference 4.6-6], the CSB repair areas were visually and mechanically inspected in 1986, after one cycle of operation. The inspection report [Reference 4.6-7] concluded that the CSB was in the same condition as it was during the baseline inspection and was acceptable for long-term service with only visual inspections required in the future. A 10-year inservice inspection was performed during the 1996 refueling outage, with emphasis placed on visual inspection of the CSB lug repair areas. No abnormal changes were observed in the repaired CSB lug areas based on comparisons to the 1984 and 1986 inspections.

The analyses and follow-up inspection reports for the repaired CSB and the expandable plugs were screened against the six TLAA criteria. It was determined that two specific elements of the repair qualify as TLAAs: 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plugs' preload based on irradiation induced stress relaxation.

As discussed in Subsection 4.3.1, the 40-year design cycles bounds the extended period of operation. Therefore the CSB fatigue analysis has been evaluated and determined to remain 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. 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 original evaluation of plug design preload verified that the design preload was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant.

The original CSB plug preload analysis was revised for increased, 60-year EOL, fluence as an 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' preload. The CSB repair plugs will therefore 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).

4.6.4 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

Small diameter Alloy 600 nozzles, such as pressurizer and Reactor Coolant System hot-leg instrumentation nozzles in Combustion Engineering designed PWRs have developed leaks or partial through-wall cracks as a result of PWSCC. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

St. Lucie Units 1 and 2 have experienced instances of Alloy 600 instrument nozzle leakage over the lives of the plants. Four Unit 2 pressurizer steam space instrument nozzles and one Unit 1 Reactor Coolant System hot-leg instrument nozzle were repaired with the half nozzle technique, due to leakage and indications.

A fracture mechanics analysis was submitted to the NRC [Reference 4.6-8] to support the St. Lucie Unit 2 pressurizer steam space half nozzle repairs performed in 1994. The fracture mechanics analysis justified the acceptability of indications in the "J" weld based on a conservative postulated flaw size and flaw growth considering the applicable design cycles. The analysis concluded that the postulated flaw size in the instrument nozzle was acceptable for the remaining design life of the plant (30 years, or 75% of the original 40-year plant design life). Consequently, only 75% of the original design cycles was assumed in the flaw growth analysis. However, this analysis has been superseded by a subsequent analysis that considered 100% of the original design cycles, as discussed below.

A half nozzle repair was implemented on a Unit 1 Reactor Coolant System hot-leg instrumentation nozzle in April 2001. In response to NRC questions regarding this repair, FPL [Reference 4.6-9] documented that the indications in the "J" weld were bounded by the fracture mechanics analysis provided in CEOG Topical Report CE NPSD-1198-P [Reference 4.6-10]. FPL also documented in that response that the CEOG topical report is applicable to the Unit 2 pressurizer steam space nozzle repairs performed in 1994.

CEOG Topical Report CE NPSD-1198-P was submitted to the NRC February 15, 2001, to obtain generic approval of the Alloy 600/690 nozzle repair/replacement programs. The CEOG report provides a bounding flaw evaluation that covers all small diameter Alloy 600/690 nozzle repairs in accordance with ASME Section XI requirements. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Units 1 and 2 UFSARs. This generic analysis bounds the Class 1 fatigue design requirements of St. Lucie Units 1 and 2. As discussed in Subsection 4.3.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the flaw growth analysis of the Unit 1 Reactor Coolant System hot-leg and the Unit 2 pressurizer steam space Alloy 600 instrument nozzle repairs have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.5 REFERENCES

4.6-1 Combustion Engineering Report CEN-367-A, "Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," Combustion Engineering, February 1991.

4.6-2 NRC Letter, "St. Lucie Units 1 and 2 - Application of Leak-Before Break Technology to Reactor Coolant System Piping," March 5, 1993.

4.6-3 CMAA Specification No. 70 (CMAA-70), "Specifications for Electric Overhead Traveling Cranes," Crane Manufacturers Association of America, Inc., 1988.

4.6-4 Miller, J. R. (NRC) letter to Williams, J. W. Jr. (FPL), "St. Lucie Unit 1 - Control of Heavy Loads, Phase I," March 4, 1985.

4.6-5 Miller, J. R. (NRC) letter to Williams, J. W. Jr. (FPL), "St. Lucie Unit 2 - Control of Heavy Loads, Phase I," April 2, 1985.

4.6-6 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - Reactor Vessel Internals and Thermal Shield; Plant Recovery Program Final Integrity and Stability of Internals - Conclusions and Findings," L-84-29, February 10, 1984.

4.6-7 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - Thermal Shield Recovery Program Final Core Support Barrel Inspection Report (Post-Cycle 6)," L-86-181, April 25, 1986.

4.6-8 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 2, In-Service-Inspection Plan, Second Ten-Year Interval, Revised Stress and Fracture Mechanics Evaluations, Pressurizer Instrument Nozzles - Supplement," L-95-220, August 2, 1995, with attached Babcock and Wilcox (B&W) Evaluation 32-1235128-02, "FM Analysis of St. Lucie Pressurizer Instrument Nozzle," Revision 2.

4.6-9 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - In-Service-Inspection Program. Third Ten-Year Interval - Replacement of RCS Hot Leg Instrument Nozzle RC-126," L-2001-131, May 24, 2001.

4.6-10 CEOG Letter (CEOG-01-052) to U. S. Nuclear Regulatory Commission, February 15, 2001, with attached CEOG Topical Report CE NPSD-1198-P, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs," Revision 0.

APPENDIX A

UPDATED UFSAR SUPPLEMENT

Since St. Lucie Units 1 and 2 have separate Updated Final Safety Analysis Reports (UFSARs), a separate UFSAR Supplement has been prepared for each Unit. The St. Lucie Unit 1 UFSAR Supplement is provided as Appendix A1 and the St. Lucie Unit 2 UFSAR Supplement is provided as Appendix A2 to this License Renewal Application.

APPENDIX A1

UNIT 1 UPDATED FSAR SUPPLEMENT

INTRODUCTION

This Appendix contains the St. Lucie Unit 1 UFSAR Supplement required by 10 CFR 54.21(d). The St. Lucie Units 1 and 2 License Renewal Application (LRA) contains the technical information required by 10 CFR 54.21(a) and (c). Chapter 3 and Appendix B of the LRA provide descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Chapter 4 of the LRA contains the evaluations of the time-limited aging analyses (TLAAs) for the period of extended operation. These LRA sections have been used to prepare the program and activity descriptions that are contained in the UFSAR Supplement.

This UFSAR Supplement will be incorporated into the St. Lucie Unit 1 UFSAR following issuance of the renewed operating license for St. Lucie Unit 1. Upon inclusion of the UFSAR Supplement in the St. Lucie Unit 1 UFSAR, changes to the descriptions of the programs and activities for their implementation will be made in accordance with 10 CFR 50.59 and St. Lucie Plant's NRC commitment management program.

ST. LUCIE UNIT 1 UFSAR

CHAPTER 1 CHANGES

lateral motion of the tubes. The control element assemblies (CEAs) consist of Inconel clad boron carbide absorber rods which are guided by Zircaloy tubes located within the fuel assembly. The core consists of 217 fuel assemblies loaded with multiple U-235 enrichments.

The reactor vessel and its closure head are fabricated from manganese moly steel internally clad with stainless steel. The vessel and its internals are designed so that the integrated neutron flux (E > 1 ~~greater than 1.0~~ Mev) at the vessel wall will be less than ~~1.91×10^{19}~~ 4.7×10^{19} n/cm^2 ~~nvt~~ over a ~~40~~ 60-year period.

The internal structures include the core support barrel, the core support plate, the core shroud, and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. The core support plate transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and minimizes the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are provided at the lower end of the core support barrel assembly.

The reactor coolant system is arranged as two closed loops connected in parallel to the reactor vessel. Each loop consists of one 42-inch ID outlet (hot) pipe, one steam generator, two 30-inch ID inlet (cold) pipes and two pumps. An electrically heated pressurizer is connected to the hot leg of one of the loops and a safety injection line is connected to each of the four cold legs.

The reactor coolant system operates at a nominal pressure of approximately 2235 psig. The reactor coolant enters near the top of the reactor vessel, and flows downward between the reactor vessel shell and the core support barrel into the lower plenum. It then flows upward through the core, leaves the reactor vessel, and flows through the tube side of the two vertical U-tube steam generators where heat is transferred to the secondary system. Reactor coolant pumps return the reactor coolant to the reactor vessel.

The two steam generators are vertical shell and U-tube units. The steam generated in the shell side of the steam generator flows upward through moisture separators and scrubber plate dryers which reduce the moisture content to less than 0.2 percent. All surfaces in contact with the reactor coolant are either stainless steel or NiCrFe alloy in order to minimize corrosion.

The reactor coolant is circulated by four electric motor driven single-suction vertical centrifugal pumps. The pump shaft leakage is minimized by mechanical seals. Each pump motor is equipped with an anti-reverse mechanism to prevent reverse rotation of any pump that is not in operation.

1.2.3.2 Engineered Safety Features and Emergency Systems

Engineered safety features systems protect the public and plant personnel in the highly unlikely event of an accidental release of radioactive fission products from the reactor system, particularly as the result of a LOCA. The safety features function to localize, control, mitigate, and terminate such accidents to hold exposure levels below applicable limits.

~~1-2.6~~ 1.2-6 Amendment No. ~~16, (1/98)~~ [LATER]

ST. LUCIE UNIT 1 UFSAR

CHAPTER 3 CHANGES

CHAPTER 3

LIST OF TABLES (Cont'd)

3.1.31 CRITERION 31 - FRACTURE PREVENTION OF REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

DISCUSSION

Carbon and low-alloy steel materials which form part of the pressure boundary meet the requirements of the ASME Code, Section III, paragraph N-330 at a temperature of + 40ºF. The actual nil-ductility transition temperature (NDTT) of the materials has been determined by drop weight tests in accordance with ASTM-E-208. For the reactor vessel, Charpy tests will be also performed and the results will be used to plot a Charpy transition curve. The NDTT as determined by drop weight test will be used to correlate the Charpy transition curve and establish nonirradiated base points for the surveillance program. See Criterion 32 and Section 5.2.3.5.

The combined static and transient loadings are limited, whenever the reactor coolant system temperature is below NDTT + 60ºF to sufficiently low values to make the probability of a rapidly propagating failure extremely remote.

All the reactor coolant pressure boundary components are constructed in accordance with the applicable codes and comply with the test and inspection requirements of these codes. These test inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding code requirements are performed. The tests and inspection performed on the reactor vessel are summarized in Sections 5.4.5 and 5.4.6.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel. The peak vessel neutron fluence at 60 ~~32 effective full power~~years ~~(EFPY)~~ at 2700 MWth is calculated to be less than 4.7 ~~3.5~~ x 10^{19} n/cm^2 (E ≥ 1 MeV)~~.~~; ~~T~~the neutron fluence at the limiting vessel material is less than 3.1 ~~1.93~~ x 10^{19} n/cm^2.

The limiting material is the ~~upper portion of~~ longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum adjusted RT~~NDT~~$_{NDT}$ at 60 years ~~32 EFPY~~ that is below the 10 CFR 50.61 screening limit ~~of 240°F~~. A surveillance program will be conducted (see Criterion 36) to allow monitoring of the NDT temperature shift of the vessel material during its lifetime. Based on the determined NDT temperature, for a given exposure, operating restrictions to limit vessel stresses would be applied as necessary. The reactor coolant system pressure will not be increased above 500 psia until reactor coolant temperature has been raised to NDTT + 60ºF. Vessel stresses resulting from a pressure of 500 psia are sufficiently low to preclude brittle fracture.

During normal start-up for power operation, the reactor will not be made critical until the reactor coolant system temperature is at least 120ºF greater than the predicted nil ductility transition temperature based on plant records of fast neutron dose to the vessel. The stress criteria include the maximum loads associated with the most severe transients during emergency conditions at operating temperature. ~~The operational restrictions that will be invoked will maintain the minimum temperature above NDTT +120 F for reactor operation.~~ This will assure that a reactivity-induced loading which would contribute to elastic or plastic deformation cannot occur below a reactor operating temperature corresponding to NDTT +120ºF.

The activation of the safety injection systems will introduce highly borated water into the primary system at pressures significantly below operating pressures and will not cause adverse pressure or reactivity effects.

The thermal stresses induced by the injection of cold water into the vessel have been examined. Analysis shows that there is no gross yielding across the vessel wall using the minimum specified yield strength in the ASME Boiler and Pressure Vessel Code, Section III.

Adverse effects that could be caused by exposure of equipment or instrumentation to containment spray water is avoided by designing the equipment or instrumentation to withstand direct spray or by locating it or protecting it to avoid direct spray.

3.1.32 CRITERION 32 - INSPECTION OF REACTOR COOLANT PRESSURE BOUNDARY

Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

DISCUSSION

Provisions are made for inspection, testing, and surveillance of the reactor coolant system boundary as described in Section 5.2.5.

The reactor vessel material surveillance program described in Section 5.4.4 conforms with ASTM-E-185-66. Sample pieces taken from the same shell plate material used in fabrication of the reactor vessel are installed between the core and the vessel inside wall. These samples will be removed and tested at intervals during vessel life to provide an indication of the extent of the neutron embrittlement of the vessel wall. Charpy tests will be performed on the samples to develop a Charpy transition curve. By comparison of this curve with the Charpy curve and drop weight tests on specimens taken at the beginning of the vessel life, the change of NDTT will be determined and operating instructions adjusted as required.

fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the reactor building and the fuel handling building.

The bellows expansion joints meet the requirements of ASME Boiler and Pressure Vessel Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water. The static head of water is always less than 35 feet.

Bellows design and construction is such that bellows will not deflect more than its designed amount. The bellows is designed to withstand a ~~40~~ 60-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion.

f) Equipment and Personnel Access

Two equipment hatches are provided. These are welded steel assemblies with 28'-0" diameter and 12'-0" diameter clear openings respectively. The 28'-0" diameter hatch cover will be welded back into position upon completion of construction. The design is such that post-weld heat treatment is not required.

The 12'-0" diameter hatch has a double gasketed flanged and bolted cover. Provision is made to pressurize the space between the gaskets to 44 psig.

Two personnel air locks are provided. These are welded steel assembles. Each lock has two double gasketed doors in series. Provision is made to pressurize the space between the gaskets. The doors are mechanically interlocked to ensure that one door cannot be opened until the second door is sealed. Provisions are made for deliberately violating the interlock by the use of special tools and procedures under strict administrative control. Each door is equipped with quick acting valves for equalizing the pressure across the doors. The doors will not be operable unless the pressure is equalized. Pressure equalization is possible from every point at which the associated door can be operated. The valves for the two doors are properly interlocked so that only one valve can be opened at one time, and only when the opposite door is closed and sealed. Each door is designed so that with the other door open, it will withstand and seal against design and testing procedures of the containment vessel. There is visual indication outside each door showing whether the opposite door is open or closed and whether its valve is open or closed. In addition, limit switches are provided to indicate remotely whether doors are open or closed. Control room annunciation is provided for indication of the Personnel Airlock. Status of the Emergency Escape Air Lock is provided on the security display panel. Provision is made outside each door for remotely closing and latching the opposite door so that in the event that one door is accidentally left open it can be closed by remote control. The air-locks have nozzles installed which will permit pressure testing of the lock at any time.

An interior lighting system and a communications system are installed.

3.9.1.6 Stress Analysis Results For Repaired Core Support

After repair of the Core Support Barrel and removal of the Thermal Shield in 1983, a stress analysis was performed to verify acceptability of repairs.

The analysis was performed for the region of the core support barrel at the thermal shield lug elevation. The conservative assumption was made that at each of the lug regions the maximum length of lateral crack was circumferential and in the same horizontal plane as the cracks in the other lugs. The point of maximum stress in the region was then established by determining the axis in the plane about which the moment of inertia of the cylindrical section in combination with the load resulted in the maximum stress. The fatigue analysis was performed utilizing the stress concentration factors resulting from the crack arrestor hole size analysis. The design fatigue curves used in the analysis are the more conservative fatigue curves published in the Winter 1982 Addenda to Section III, Appendix I, Figures I-9.2.1 and I-9.2.2.

In addition to the Code Analysis, a confirmatory stress analysis of the core support barrel was performed using sophisticated finite element techniques. Overall effects and local effects of cracks in the core support barrel were evaluated by comparing stress distributions to those of an uncracked barrel. The conclusion of the confirmatory analysis was that the analysis considering the horizontal crack length in the same horizontal plane was conservative.

A summary of the Code Analysis results is shown in Table 3.9-3b.

An evaluation of the cracks in the core support barrel on the basis of fracture mechanics considerations was performed. After discussion with consultants on fracture mechanics it was concluded that insufficient data for the barrel material in a pressurized water reactor environment for service in excess of 10^{11} cycles was available. Because of the lack of materials data and the length of cracks in the core support barrel extremely conservative assumptions would have had to be made. The decision was made to use crack arrestor holes sized to reduce stress concentrations to magnitudes compatible with the ASME code fatigue limitations.

The stress concentration factors for a crack with a crack arrestor hole at each end were calculated using available theoretical solutions of stress distributions in plates with openings. (23) The adequacy of the solutions was verified through comparisons with finite element analyses of typical crack geometries and loading conditions.

The "equivalent ellipse" concept is useful in calculating stress concentration factors for a crack with crack arrestor holes at each end. For an elliptical hole in an infinite plate in tension, the stress concentration factor, K_t, is given by:

$$K_t = 1 + \cancel{s}\,\underline{2}\sqrt{\frac{b}{2r}}$$

Where: b = major length of elliptical hole
r = minimum radius of elliptical hole

3.9-16a Amendment No. ~~16, (1/98)~~ [LATER]

3.9.2 ASME CODE CLASS II AND III COMPONENTS

3.9.2.1 Design Conditions

The design pressure, temperature and other conditions that were considered in the design of each system containing Code Class 2 or 3 mechanical components are listed in Table 3.9-4.

3.9.2.2 Design Loading Combinations

The design loading combinations considered in the component design are: normal (operating design) pressure, temperature and thrust loads combined with seismic, hurricane or tornado loads. Seismic loads and hurricane and tornado loads are not assumed to act concurrently. The design loaning conditions are categorized as design, normal, upset, emergency, and faulted. The stress limits associated with each of the design loadings categories Code Class 2 or 3 components are given in Table 3.9-3A, and for piping in Table 3.9-3.

Tue forces and moments acting on any component in the piping system are supplied to the manufacturer so that it can be insured that the component will function under the applied loads

Loads resulting from transients appropriate to specified plant operating conditions have been considered and accommodated by design. These conditions have been analyzed in accordance with applicable code requirements as an independent case. The transient operating conditions accounted for in the design of the reactor coolant pressure boundary (NSS vendor's scope) is provided in Section 5.2.1.2. Cyclic loading considerations for equipment outside the NSS vendor's scope is discussed below.

The ASME code does not require cyclic analyses for Class 2 and 3 components. Equipment specifications for pumps specify "maximum" moments and forces at the pump nozzles. These maximum moments and forces envelop operating transient loading conditions appropriate for the component. (See Table 3.9-3A footnote 2). For Class 2 and 3 piping the dynamic conditions resulting from fast valve closure and relief valve operation are analyzed as shown in loading combination 3 of Table 3.9-3. These dynamic conditions envelop the operating transients.

For Class I piping and fitting assemblies, fatigue analysis has been performed to ensure the usage factor is adequate for the ~~40~~ 60-year design life. The applicable transients have been assigned operating condition categories, normal (14), upset (U), test(T), emergency (E), or faulted (F). Cyclic loading combinations considered for Class I piping and assemblies include:

Following the above flow at 40°F from the low pressure safety injection headers through the safety injection lines to the cold leg nozzles will be maintained at 2000 gpm per line (from low pressure safety injection pumps)until equilibrium is reached. This is a "faulted" operating condition.

d. Safety Injection Return Lines

The safety injection return lines (I-1-SI-118, I-1-SI-120, I-1-SI-123 and I-1-SI-125) are subject to 2000 occurrences of a step change from 130°F and 1100 psia to 120°F and 200 psia. This transient occurs upon opening the return line pneumatic valves to relieve the pressure accumulated between the safety injection check valves (V-3113, V-3114 and V-3217 typical). The flow rate varies from 0 to 40 gpm during those step changes. This transient occurs periodically during the operation of the plant.

e. Shutdown Cooling Suction Lines

The shutdown cooling suction lines, I-12- RC-147 and 162, I-10-SI-127 and 130, as a normal operating condition, be subject to 500 occurrences of shutdown cooling with a flow of 3000 gpm, an initial temperature of 350°F max and pressure and temperature varying as appropriate for cooldown beyond 350 °F.

f. Letdown Line

Five hundred (500) heat-up cycles with a flow of 80 gpm and temperature increasing at 100°F/hr from 70°F to 550°F and pressure increasing from atmospheric to 2250 psia over this period. This condition should be considered as a "normal" operating condition.

Five hundred (500) cooldown cycles of flow at 29 gpm and temperature decreasing from 550°F to 140°F at a rate of 100°F/hr and pressure decreasing from 2250 psia to atmospheric. This condition should be considered as a "normal' operating condition. ~~Following transients experienced by the reactor coolant pipe:~~

Operating Condition Category		Plant Conditions	Occurrences
N	a –	Heatup, 100°F/hr	500
N	b –	Cooldown, 100°F/hr	500
N	c –	Loading, 5%/min.	15,000
N	d –	Unloading, 5%/min.	15,000
N	e –	Step Load Increase, ~~±10%~~ +10%	2,000
N	f –	Step Load Decrease, ~~±10%~~ -10%	2,000
U	g –	Reactor Trip	400
U	h –	Loss of Reactor Coolant System Flow	40
U	i –	Loss of Turbine-Generator Load	40
E	j –	Loss of Secondary Pressure	5
N	k –	Purification	1,000
N	l –	Low Volume Control & Makeup	2,000
N	m –	Boric Acid Dilution	8,000
U	n –	Loss of Charging Flow	200
U	o –	Loss of Letdown	50
U	p –	Regenerative Hx Isolation Long-term	~~80~~ 150
U	q –	Regenerative Hx Isolation Short-term	40

3.9-22 Amendment No. ~~18, (04/01)~~ [LATER]

results on one or more of the following tests: radiographic, liquid penetrant, magnetic particle, ultrasonic or hydrostatic. The seismic analysis or testing described in Section 3.9.1.2 provided by the manufacturer also serves to demonstrate compliance with the applicable sections of the codes.

3.9.2.8 Operational Cycles

The auxiliary feedwater pumps may be subjected to the following number of operational cycles during the plant life: testing ~~480~~ 720 cycles in which the pumps run for 15 minutes during each test; plant cooldown, 500 cycles; and hot standby, 15,000 cycles. In all cases the electrically driven pumps are preferred for operation with the steam turbine driven pump on standby. However, the steam turbine driven pump may be subjected to 300 cycles of the complete system blacking out including the loss of the standby diesel generators. During the performance of the operation the motor operated valves on the discharge are kept closed and the pumps operated on the minimum recirc flow.

Both the electrically driven and the steam turbine driven pumps are capable of withstanding without any damage instantaneous loss of suction should this occur inadvertently.

The component coolant pumps are run continuously while the plant is in operation and may be subjected to 500 shutdown cooling cycles. One of the three component cooling pumps will be on standby at all times. Standby condition will be alternately shared among the three pumps.

The containment spray pumps are ~~will be~~ tested every refueling outage~~year~~ and thus will undergo approximately 40 lifetime full-flow testing cycles.

 Amendment No. ~~17, (10/99)~~ [LATER]

Table 3.9-3A (con't.)

(5) Loading conditions, i.e., Seismic, Tornado or Hurricane (as appropriate) plus normal operating loadings are considered. Allowables employed by the component manufacturer for support materials varied from 1.33 normal allowable stresses to yield stresses as listed in ASME or AISC codes.

~~TABLE 3.9-3b~~

~~Normal Operation Plus Upset Conditions~~

~~Stress Category~~	~~Calculated Stress* psi~~	~~Allowable Stress Psi~~
~~P_m~~	~~5,500~~	~~16,200~~
~~$P_m + P_b$~~	~~7,300~~	~~24,300~~
~~$P_m + P^h + Q$~~	~~21,000~~	~~48,600~~
~~Fatigue Usage Factor < 1~~		

~~*Includes Seismic~~

~~Faulted Condition~~

~~Stress Category~~	~~Calculated Stress psi~~	~~Allowable Stress Psi~~
~~P_m~~	~~21,200~~	~~38,900~~
~~$P_m + P_b$~~	~~42,500~~	~~50,000~~

Note - Table 3.9-3b is revised and moved to new UFSAR page 3.9-48a.

TABLE 3.9-3B

CORE SUPPORT BARREL MIDDLE CYLINDER CODE ANALYSIS RESULTS

Normal Operation Plus Upset Conditions

Stress Category	Calculated Stress* psi	Allowable Stress psi
P_m	6,100	16,100
$P_m + P_b$	8,100	20,700
$P_m + P_b + Q$	23,200	48,300
Fatigue Usage Factor < 1		

*Includes Normal Operating Pressure plus OBE

Faulted Condition

Stress Category	Calculated Stress** psi	Allowable Stress psi
P_m	8,500	38,600
$P_m + P_b$	43,800	49,700

** Includes SSE plus LOCA

P_m = Membrane Stress

P_b = Bending Stress

Q = Secondary Stress

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Near the bottom of the extension shaft is a larger diameter section which allows the upper guide structure to pick up the extension shafts as the upper guide structure is removed from the reactor vessel.

The drive shaft is a long tube made of 304 stainless steel. It is threaded and pinned to the extension shaft. The drive shaft has circumferential notches along the shaft to provide the means of engagement to the control element drive mechanism.

The magnet assembly consists of a housing, magnet and plug. Two, 2-inch cylindrical Alnico-V magnets with a minimum flux density of 325 gauss are used in the assembly. This magnet assembly is used to actuate the reed switch position indication. The magnets are contained in a housing which is plugged at the bottom. The housing provides a means of attaching the lifting tool for disengaging the CEA from the extension shaft.

In order to engage or disengage a CEA to or from the extension shaft, a special gripper operating tool is attached to the top of the extension shaft assembly when the reactor vessel head has been removed. One part of the tool is attached to the extension sleeve to hold this portion of the extension shaft assembly fixed. Another part of the tool is attached to the operating rod at the magnet assembly and is used to raise the operating rod to conform to the pattern of the slot in the extension sleeve. Withdrawing of the operating rod raises the plunger which in turn allows the fingers of the collet type gripper to collapse to a smaller diameter and allows separation of the extension shaft assembly from the CEA.

4.2.3.1.3 Design Evaluation

(a) Prototype Tests

A prototype magnetic jack type standard CEDM was subjected to accelerated life tests accumulating 100,000 feet of travel equivalent to a ~~40~~ 60-year lifetime.

The first phase of the accelerated life test consisted of continuous operation of the mechanism at 40 in/min over a 137 inch stroke lifting and lowering 230 pounds for a total travel of 32,500 feet. This test was performed at simulated normal reactor operating conditions of 600ºF and 2200 psig. Upon completion of the test, the motor bearing surfaces were inspected and measured. A maximum bearing wear of .003-inch was measured. This degree of wear is considered acceptable based on the ~~40~~ 60-year design life.

4.2-38 Amendment No. ~~16 (1/98)~~ [LATER]

4.3.2.9 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that the peak vessel neutron fluence at 60 ~~32 effective full power~~ years ~~(EFPY)~~ at 2700 MWth is calculated to be less than 4.7 ~~3.7~~ x 10^{19} n/cm^2 (E > 1 MeV). The neutron fluence at the limiting vessel material at 60 years ~~32 EFPY~~ is less than 3.1 ~~2.77~~ x 10^{19} n/cm^2.

The limiting material is the ~~upper portion of~~ longitudinal weld seam 3-203 at the ~~15~~ 15°, 135° and 255° azimuthal locations with a maximum adjusted RT_{NDT} at 60 years ~~32 EFPY~~ that is below the 10 CFR 50.61 screening limit ~~of 240°F~~.

4.3.2.10 References for Section 4.3.2

1 XN-75-27(A), Supplement 1, September 1976.

2 XN-75-27(A), Supplement 2, December 1977.

3 XN-75-27(A), Supplement 3, November 1980.

4 XN-NF-84-12, "St Lucie Unit 1 Cycle 6 Safety Analysis Report Reload Batches XN-1 and XN-IA", Exxon Nuclear Company, February 1984.

5 XN-CC-28, Revision 5, "XTG - A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing", Exxon Nuclear Company, July 1979.

6 XN-75-27(A), "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors", Exxon Nuclear Company, June 1975.

7 XN-75-27(A), Supplement 4, December 1985

8 WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," June 1988 (Westinghouse Proprietary)

4.3.3 COMBUSTION ENGINEERING ANALYTICAL METHODS (CYCLES 1-5)

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few-group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include spatial effects in those portions of the neutron energy spectrum where volume homogenization is inappropriate, e.g., the thermal neutron energy range. Most of the calculations are performed with the aid of computer programs embodying analytical procedures and fundamental nuclear data consistent with the current state of the art.

A summary of the analytical tools employed is given below. Comparisons between calculated and measured data which validate the design procedures are presented in Section 4.3.3.1.2. As improvements in analytical procedures are developed and improved nuclear data become available, they will be added to the design procedures, but only after validation by comparison with related experimental data.

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5.2.1.1 Functional Performance Requirements

The function of the reactor coolant system is to remove heat from the reactor core and transfer it to the secondary system by the forced circulation of pressurized borated water. The borated water serves both as a coolant and neutron moderator. The reactor coolant system is designed for the normal operation of transferring 2710 Mwt from the reactor core (2700 Mwt) and reactor coolant pumps (10 Mwt) to the steam generators.

The reactor coolant system also serves as a pressure boundary having a high degree of leak tightness. The integrity of this pressure boundary is assured by appropriate recognition of operating, seismic and/or accident stress loadings. The normal operating pressure of the reactor coolant system is approximately 2235 psig.

The system design temperature and pressure are conservatively established and exceed the combined normal operating value and those resulting from anticipated transients. The effects of instrument error and the response characteristics of the control system are included in the design rating of the systems. The change due to the anticipated transients also considers the effect of reactor core thermal lag, coolant transport time, system pressure drop and the characteristics of the safety and relief valves.

Test pressures for the system and individual components are in accordance with the codes given in Table 5.2-1. The ASME Code specifies that the hydrostatic test pressure shall be 125 percent of design pressure. The allowable number of such tests are limited to those allowed by usage factor analyses.

~~The reactor coolant system is designed for an operating life of 40 years.~~

5.2.1.2 Transients Used in Design and Fatigue Analyses

The following design cyclic transients, which include conservative estimates of the operational requirements for the components, were used in the fatigue analyses required by the applicable codes listed in Table 5.2-1. (Note: Differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked). The evaluation for a 60-year plant design life concludes the design cycles listed below, which were based on a 40-year design life, envelope the 60-year plant design life. See Section 18.3.2.1.

a) 500 heatup and cooldown cycles during the design life of the components in the system with heating and cooling at a rate of 100ºF/hr. between 70ºF and 532ºF (653ºF for the pressurizer). This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred. The heatup and cooldown rate of the system is administratively limited to a value that will assure that these limits will not be exceeded.

b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

TABLE 5.4-3

CAPSULE REMOVAL SCHEDULE(5)

Location on Vessel Wall	Approximate Removal ~~Time~~ Schedule (EFPY)	Predicted Fluence n/cm^2	Lead Factor (3)
97° (1)	4.67	~~5.5~~ 6.27 x 10^{18}	------
104° (1)	9.515	~~7.16~~ 9.09 x 10^{18}	------
284° (1)	17.23	1.41 x 10^{19}	------
263°	~~21~~ 38	~~2.78~~ 4.40 x 10^{19}	1.37
83° (2) (4)	>38 / Standby	~~4.24 x 10^{19}~~ ------	1.37
277°(~~2~~ 4)	Standby	------	1.37

(1) Numbers for these capsules are actual.

(2) Fifth capsule is not required to be tested per ASTM E185. It is reserved as standby should an additional license period be considered.

(3) Lead Factor is defined as the capsule fluence/RV base metal peak fluence.

(~~2~~ 4) The capsule removal times were switched for the 83º and 277º capsules. The capsule at 277º was found to be missing its ACME threaded top during a 1996 vessel inspection (Condition Report 96-1064). Without the top, a special removal tool will be required to retrieve the 277º capsule. Both capsules contain identical samples and receive similar fluence since they are 180º apart.

(5) Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

5.5.5 REACTOR COOLANT PUMPS

5.5.5.1 Design Bases

The reactor coolant pumps which circulate the reactor coolant through the reactor coolant system are designed to:

a) Circulate reactor coolant with the chemistry identified in Table 9.3-8 at the flows listed in Table 5.5-9~~ for a design life of 40 years~~.

b) Meet the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class A. Winter 1967 Addenda.

c) Meet the transient operating condition categories listed in Section 5.2.1.2.

d) Provide sufficient moment of inertia to reduce the flow decay through the core upon loss of pump power.

e) Prevent reverse rotation of the pump upon loss of pump power with the other pumps operating.

f) Operate without cooling water for periods up to 10 minutes without incurring seal damage.

Reactor coolant pump parameters and design requirements are listed in Table 5.5-9.

5.5.5.2 Description

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal motor driven pumps as shown in Figure 5.5-6. The design parameters for the pumps are given in Table 5.5-9.

The reactor coolant pump assembly consists of the pump case, rotating assembly containing the impeller which is keyed and locked to the shaft, pump case cover, motor adapter and motor. The motor is connected to and supported by the pump case through the motor mount adapter. There are two openings on opposite sides of the motor mounts that provide access for assembly of the flanged rigid coupling between the motor and pump and for seal cartridge replacement.

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All portions of the spray systems which are designed to recirculate radioactive water collected in the containment sump are designed to operate in the radiation environment associated with normal plant operation plus the maximum hypothetical accident (MHA). ~~System components such as valve operators, valve packing and pump motors and seals have been specified to operate through an integrated radiation dose of 5 x 10^4 Rad (based on 40 years operation plus MA~~).

Normal operating conditions allow the containment fan coolers to function in a relatively low pressure/low temperature (approximately 0 psig/ 120ºF) atmosphere with a 40 percent relative humidity and average radiation dose of 1 rad/hr.

Upon occurrence of a LOCA, the service environment is altered such that: (1) temperature increases from 120ºF to a maximum, (2) pressure increases from 0 psig to a maximum, (3) humidity increases to 100 percent, and (4) the radiation dose increases to approximately 2 x 10^6 rad/hr. Also the fan coolers are subjected to a 1720 ppm borated spray. The fan coolers are designed to operate in the post-accident environment for at least one year. Discussion of the environmental qualifications of the fan motors is given in Section 3.11.

Fan and motor bearings are lubricated with a high temperature lubricant suitable for an integrated radiation exposure of 5 x 10^8 rad. Lubrication is adequate for fan and motor operation for a period of one year under post-MHA conditions. These bearings will be inspected and re-lubricated in accordance with the site preventative maintenance program on a refueling outage basis.

6.2.2.3.4 Natural Phenomena

All components of the containment heat removal system which are necessary to support the system safety functions have been designed as seismic Class I and are installed in seismic Class I structures. Seismic Class I has been specified in purchase specifications, and vendors have substantiated either through test, calculational and/or operational data that system components will remain operable under the design basis earthquake loads.

Refer to Sections 3.7.3 and 3.9 for seismic analysis of system piping and seismic qualification of components, respectively.

6.2.2.4 Testing and Inspection

6.2.2.4.1 Containment Spray System

Performance tests are conducted in the shop to establish pump characteristics. Transient tests are conducted at the pump design point to establish pump ability to withstand a temperature transient of 40ºF to 250ºF in 10 seconds, conservatively simulating the switchover from refueling water tank suction to containment sump suction. Net positive suction head (NPSH) requirements for the pump capacity range are verified by a suction pressure suppression test for each pump.

Operating procedure restrictions and design features are provided so that the normal safety injection system lineup is not altered except under reduced reactor coolant system pressure conditions. Valve interlocks on the suction line to the low pressure safety injection pumps preclude initiation of shutdown cooling until pressurizer pressure is below 267 psia. System alignment will not be altered until this low pressure condition is reached. Since several hours must elapse after reactor shutdown before this condition is reached, the required level of core cooling is significantly reduced. Therefore, in the event of a pipe break with the system in the shutdown cooling mode, sufficient time exists for operator action to safely control the accident.

This shutdown procedure will occur at most a few times per year. For each shutdown, there is a period of about 25 hours during which automatic initiation of the ECCS is not available, the time required to reduce temperature to the refueling temperature.

6.3.3.3 Service Environment

All safety injection, system components and associated electrical equipment have been examined with regard to capability to withstand post-accident environmental conditions. The design of each component has been determined that the design criteria encompass the most severe condition the equipment will encounter.

Components such as remotely operated valves, and instrumentation and control equipment located within the containment required for initiation of safety injection system operation are designed to withstand the post-accident containment conditions of temperature, pressure, humidity, chemistry and radiation for the time period required.

All other safety injection components required to maintain a functional status have been located outside containment to eliminate exposure of this equipment to the post-LOCA containment conditions. The equipment outside containment (i.e., reference to Figure 6.3-2 indicates location of equipment inside or outside of containment) is designed in consideration of the chemical and radiation effects associated post-LOCA operation.

~~The design life of the safety injection pumps is 40 years, corresponding to the life of the plant.~~ Design pressures and temperatures are in excess of the maximum pressures and temperatures seen during normal operating or accident conditions. Materials of construction for the pumps are compatible with the expected water chemistry under LOCA conditions. A radiation resistance requirement (10^7rads) has also been placed on the pumps, which is in excess of the calculated dose based on plant operation of ~~40~~ 60 years plus a LOCA ~~at the end of the 40 years~~. All power operated valves in the safety injection system which might require operation in the post-LOCA period are located outside containment and are designed in consideration of the attendant spray and radiation environment.

Section 3.11 contains additional discussion concerning the environmental design of mechanical and electrical equipment.

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apply an equivalent maximum horizontal force on the crane calculated to be about 2 1/2 percent of the lifted load, which is less than the original design impact of 10 percent lateral and longitudinal.

The above summarizes how uncontrolled cask descent and potential anomalies were accommodated in the design. The crane is well suited for its intended service, and cask drops from the elevation of the "L" shaped entrance into the spent fuel pool, although conceivable, are unlikely. This notwithstanding, cask drops from this elevation and in various orientations were postulated, and scoping analyses of cask impact for the ten element (about 105 ton) and single element (about 25 ton) casks were conducted. These studies indicate that for the ten element cask sufficient cask energy could be obtained to void the leak tight integrity of the structure thereby causing loss of coolant. Fuel pool integrity is maintained for the single element cask drop. in view of this, Technical Specification limitations imposed ensure that the maximum load which may be handled by the cask crane is a loaded single element cask (about 25 tons).

Use of single element fuel cask results in increasing the crane design factors as follows:

COMPONENT	D.F.	CONDITION
Rope (Main Hoist)	29	Breaking Strength
Pins. Axles, etc.	21	Yield Strength
Machinery	21	Ultimate Strength
Rope (Aux Hoist)	25	Breaking Strength
Structural Steel	8.4	Yield Strength
Hook	12.6	Yield Strength
Hook	21	Ultimate Strength

The above design factors will limit the working stresses to a small fraction of the stress val~~v~~ues associated with component failure. The crane is designed for a minimum of 20,000 fuel load cycles. Reducing the allowable load to a single element cask increases the number of fuel load cycles to in excess of 200,000, which is well beyond the anticipated lifetime loading of the crane.

~~in excess of 200,000. The crane would be subjected to about 6400 full load cycles over the 40 year lifetime.~~

The Staff requires that a cask drop be postulated. In order to comply with this position an analysis has been made of the structural and radiological consequences associated with a 25 ton cask drop from the maximum height of 58 feet above the fuel pool floor.

The cask used in the analysis has a maximum weight when loaded of 25 tons, a base diameter of 33 inches and a height of 195 inches. The physical dimensions of the spent fuel pool are shown in Figures 1.2-18 and 1.2-19.

The cask drop is postulated to occur during normal operating conditions, i.e., the forces acting at the time of the drop include the dead weight of concrete, dead weight of steel, equipment, the weight of water in the pool to elevation +60 ft, and the thermal stresses in the concrete resulting from a water temperature of 150ºF. Ultimate strength design is used with a load factor of 1.0 as outlined in Section 3.8.1.5. Seismic loads in combination with the cask drop load is not a design basis load combination for this facility. The occurrence of an earthquake during the time when the cask is suspended over the pool is very unlikely, about two to three orders of magnitude less than the probability of the seismic occurrence. Accordingly the seismic plus cask drop loading combination was obviated by the acceptably low probability associated with this postulated event.

A number of cask free fall trajectories were analyzed to determine if the leaktight barrier of the pool could be breached and to determine the extent ~~)~~of possible damage to stored fuel. The vertical drop has been determined to be the critical loading condition since it results in the maximum energy at impact. The critical target area for this drop is the cask storage area since the thickness of concrete there is 6 ft compared to 9.5 ft for the rest of the pool. A cask dropping in the tipped position was also considered. It will impact on the cask pit area and the main mat area, thus distributing its total energy between two areas. In addition, the impactive load for the tipped drop is less than that for the vertical drop. Therefore with regard to pool integrity, the tipped drop is not limiting.

The maximum velocity at impact for the vertical drop is determined to be 55 fps assuming a free fall through air from the point of maximum lift to elevation 60' as shown on Figure 9.1-19 with the remainder of the descent through water. The velocity of the cask in water is determined using the equation of motion by Riccato (Reference 1).

$$v^2 = A - Be^{-cx}$$

where:

$$A = \frac{W - Fb}{K}$$

$B = A - Vo^2$, Vo = initial velocity at x = 0

C = 2gk/W

at or near the surface, which are the appropriate consideration for this piping. Experience indicates that large flaws, if present, would be detected during hydrostatic testing, i.e., the hydro provides a satisfactory system integrity check. Based on a considerable experience base with thin walled carbon steel pipe, it is concluded that (i) the use of qualified weldors, (ii) industry approved welding procedures, (iii) visual inspection procedures,and (iv) hydrostatic testing results in piping integrity of an acceptable confidence level. The benefit afforded by the Article ND-5220 NDE requirement is simply that derived from the elimination of small surface flaws in weld areas.

Small surface or internal flaws are local discontinuities that produce local discontinuity type stresses. The relevant consideration is whether or not these flaws can grow in service to a point where the integrity of the piping could be compromised. Defects or notches of one type of another are nearly always present in carbon steel parts because of design requirements, manufacturing and installation methods, or surface conditions. The presence of these local discontinuities may appreciably affect the fatigue properties of the carbon steel piping.

Figure F-106(a) of USA Standard B31.7, Nuclear Power Piping (1969) provides this Code's allowable fatigue curve for carbon and alloy steels with metal temperatures not exceeding 700ºF. The fatigue properties of carbon steel are such that if the alternating stress intensity (Sa) is less than 10,000 psi, fatigue failure of the pipe is not a concern, i.e., the stresses in the pipe do not exceed the endurance limit of the material --- a crack will not be initiated.

The CCW piping may cycle from a low pressure (static head from the component cooling surge tank) and ambient temperature when "N" loop sections are secured, to the maximum operating conditions of 100 psig and 120ºF. The system will see a modest number of such cycles during the plants' lifetime. For an 8 inch schedule 40 pipe the cyclic variation in hoop stress is from 0 to about 1,300 psi. (Since the piping is not subjected to rapid temperature transients, thermal stresses are negligible.) Accordingly, the alternating stress intensity (Sa) is very low, less than 1000 psi. Since Sa is more than an order of magnitude below the values where fatigue becomes a relevant consideration, it is concluded that flaws will not grow, i.e., their presence does not imperil CCW pipe integrity.

Appendix A to ASME Section XI (1974) provides a method to be utilized for the evaluation of flaws detected in metals during inservice inspection. This methodology is normally applied to thick sections where there is a likelihood of flaws and the presence of flaws may be a weighty consideration. This notwithstanding, the methods have been applied to the CCW piping as an alternate means of demonstrating the acceptability of the presence of flaws in the CCW piping. A hypothetical flaw through the pipe wall was postulated. Flaw parameters were selected to maximize the stress intensity factor (K_I). Even for this extreme case (piping would not pass the hydro), the low applied stresses in the CCW piping results in a low stress intensity factor range - (ΔKI). The stress intensity factor range is so low that it falls off of Section XI figure A-4300-1. This indicates that the crack growth rate is extemely small --- less than 10^{-8} inches/cycle. If the CCW system were removed from service, depressurized and returned to service for over 14,000 cycles ~~daily for 40 years~~ (the system might see one or two such cycles a year),the flaw would grow less than 0.00014 inches. This flaw growth is negligible.

TABLE 9.3-9

DESIGN TRANSIENTS
Regenerative and Letdown Heat Exchangers

Transient	Cycles in ~~40~~60 Years	Variation Level Initial - Final	Rate	Letdown Flow Initial - Final (GPM)	Charging Flow (GPM)
Step Power Change	2000	90% - 100%		40 - 89 (100 sec) 89 - 40 in 11.7 min	44
Step Power Change	2000	100% - 90%		40 - 29; 29 - 40	44 (88 2.8 min)
Ramp Power Change	15000	15% - 100%	5%/min	40 - 128 in 16 min 128 - 40 in 17 min	44
Ramp Power Change	15000	100% - 15%	-5%/min	40 - 29; 29 - 40 in 27 min	44-88-132; 132-88-44 in 19 min
Reactor Trip	440	100% - 0%		40 - 29; 29 - 40 in 30 min	44-88-132; 132-88-44 in 22 min
Loss of Load	45	100% - 0%		40 - 116-29; 29 - 40 in 28.3 min	44-88-132; 132-88-44 in 20 min

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TABLE 9.3-9 (Cont'd)

Transient	Cycles in ~~40~~60 Years	Variation Level Initial - Final	Rate	Letdown Flow Initial - Final (GPM)	Charging Flow (GPM)
Maximum Purification	1000	-		40-128; 128-40	44-88-132; 132-88-44
Loss of Charging	100	-		40 - 0 0 - 40	44-0 0-44
Loss of Letdown	50	-		40 - 0 0-128-40 15 min after restart	44
Short Term Isolation - Regen. Ht. Exch.	400	-		40 - 0 0 - 40	44-0 0-44
Long Term Isolation - Regen. Ht. Exch.	800			40 - 0 0 - 40	44-0 0-44
Boron Dilution	10,000	-		40 - 128 128-40	44-132 132-44

Amendment No. ~~18, (04/01)~~[LATER]

ST. LUCIE UNIT 1 UFSAR

CHAPTER 18.0
[NEW]

18.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES ACTIVITIES

The integrated plant assessment for license renewal identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This chapter describes these programs and their planned implementation.

This chapter also discusses the evaluation results for each of the plant-specific time-limited aging analyses performed for license renewal. The evaluations have demonstrated that: the analyses remain valid for the period of extended operation; the analyses have been projected to the end of the period of extended operation; or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

No 10 CFR 50.12 exemptions involving a time-limited aging analysis as defined in 10 CFR 54.3 were identified for St. Lucie Unit 1.

18.1 NEW PROGRAMS

18.1.1 CONDENSATE STORAGE TANK CROSS-CONNECT BURIED PIPING INSPECTION

A one-time visual inspection will be performed to determine the extent of the loss of material due to pitting and microbiologically influenced corrosion on the external surfaces of the buried piping that connects the St. Lucie Unit 1 and Unit 2 condensate storage tanks. The results of this inspection will be evaluated to determine the need for additional inspections. The inspection will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.1.2 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

The Galvanic Corrosion Susceptibility Inspection Program manages the aging effect of loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The program involves selected, one-time inspections on the surfaces of piping and components with the greatest susceptibility to galvanic corrosion. Baseline examinations in select systems will be performed and evaluated to establish if the corrosion mechanism is active. Based on the results of these inspections, the need for follow-up examinations or programmatic corrective actions will be established. The program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.1.3 PIPE WALL THINNING INSPECTION PROGRAM

The Pipe Wall Thinning Inspection Program manages the aging effect of localized loss of material due to erosion of the internal surfaces of stainless steel Auxiliary Feedwater System piping downstream of the recirculation orifices. Examinations will be performed using volumetric techniques such as ultrasonic testing or radiography. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.1.4 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

The Reactor Vessel Internals Inspection Program manages the aging effects of irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness, loss of mechanical closure integrity of bolted joints, and dimensional changes due to void swelling. The program consists of one-time VT-1 visual examinations and, in some cases, enhanced VT-1 examinations of selected reactor vessel internals parts to be performed early during the period of extended operation. These inspections will be performed in addition to and in conjunction with the examinations required by the St. Lucie ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The examinations will be focused on areas of potential aging effects based on the highest projected combination of stress and fluence. For cast austenitic stainless steel (CASS) parts, analytical methods will be used to identify reactor vessel internals parts that are susceptible to loss of fracture toughness due to thermal embrittlement.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria.

18.1.5 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 the NRC with a report describing the inspection plan prior to its implementation. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1.

18.1.6 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

The St. Lucie Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (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. Aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2 EXISTING PROGRAMS

18.2.1 ALLOY 600 INSPECTION PROGRAM

This program manages the aging effect of cracking due to primary water stress corrosion for susceptible Alloy 600 components within the Reactor Coolant System (RCS) pressure boundary. This includes the 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 piping dissimilar metal welds. The program includes examinations of the reactor vessel head penetrations to detect crack initiation consistent with St. Lucie Plant's response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," and ongoing Nuclear Energy Institute (NEI) and Electric Power Research Institute (EPRI) Materials Reliability Project recommendations. Visual examination of external surfaces of susceptible locations during outages, which is included as part of the Boric Acid Wastage Surveillance Program, is also utilized to manage cracking.

18.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

18.2.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program inspections identify and correct degradation in Class 1, 2, and 3 components and piping. The program manages the aging effects of loss of material, cracking, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The program provides for inspection and examination of accessible components, including the reactor vessel, reactor vessel internals, steam generators, welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. This enhancement will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.2.2 ASME SECTION XI, SUBSECTION IWE INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsection IWE Inservice Inspection Program inspections identify and correct degradation of pressure-retaining components and their integral attachments to the Class MC steel Containment. The program manages the aging effects of loss of material and loss of seal. The program provides for inspection and examination of Containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE.

18.2.2.3 ASME SECTION XI, SUBSECTION IWF INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsection IWF Inservice Inspection Program inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This program manages the aging effect of loss of material. The scope of the program provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

18.2.3 BORAFLEX SURVEILLANCE PROGRAM

The Boraflex Surveillance Program manages the aging effect of change in material properties for the Boraflex material in the spent fuel storage racks.

The program will be enhanced to include areal density testing (in lieu of blackness testing) of the encapsulated Boraflex material in the spent fuel storage racks prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.4 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

The Boric Acid Wastage Surveillance Program manages the aging effects of loss of material and loss of mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. The program addresses the RCS and structures and components containing, or exposed to, borated water. This program utilizes systematic inspections, leakage evaluations, and corrective actions to ensure that boric acid corrosion does not lead to degradation of the pressure boundary or the structural integrity of components, supports, or structures in proximity to borated water systems. This program includes commitments in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

Portions of the Waste Management System within the scope of license renewal are not currently included in the Boric Acid Wastage Surveillance Program. As such, the scope of the program will be enhanced to include these components and to provide for the inspection and evaluation of adjacent structures and components when leakage is identified. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.5 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program manages the aging effects of loss of material, cracking, and fouling for primary and secondary systems, closed cooling water, and fuel oil systems, structures, and components. The aging effects are minimized or prevented by controlling the chemical species that cause the underlying mechanism(s) that results in these aging effects. Alternatively, chemical agents, such as corrosion inhibitors and biocides, are introduced to prevent certain aging effects. The program includes sampling activities and analysis. The program provides assurance that elevated levels of contaminants and oxygen do not exist in the systems, structures, and components covered by the program, and thus prevents and minimizes the occurrences of aging effects.

18.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is not credited as an aging management program; however, program evaluations of electrical equipment are identified as time-limited aging analyses.

Equipment covered by the Environmental Qualification Program has been evaluated to determine if the existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment initially qualified for 40 years or less. When analysis cannot justify a qualified life in excess of the license renewal period, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life in accordance with the Environmental Qualification Program.

18.2.7 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program is considered a confirmatory program to ensure that fatigue time-limited aging analysis assumptions remain valid for the period of extended operation; it is not credited as an aging management program.

The Fatigue Monitoring Program is designed to track design cycles to ensure that RCS components remain within their design fatigue limits. Design cycle limits for St. Lucie Unit 1 are provided in Sections 3.9.2.2, 5.2.1.2, and 5.5.1.1. The specific fatigue analyses validated by the Fatigue Monitoring Program are associated with the reactor vessel, reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and RCS Class 1 piping. Administrative procedures provide the methodology for logging design cycles. These procedures will be enhanced to provide guidance in the event design cycle limits are approached. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.8 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the aging effect of loss of material for the components of the Fire Protection System. Additionally, this program manages the aging effect of loss of material for structural components associated with fire protection. Appendix 9.5A contains a detailed discussion of the Fire Protection Program.

18.2.9 FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The Flow Accelerated Corrosion Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping associated with the Main Steam, Reactor Coolant (steam generators), Main Feedwater and Blowdown Systems, and is based on industry guidelines and experience. The program includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and follow-up inspections.

The Flow Accelerated Corrosion Program will be enhanced to address internal and external loss of material of drain lines and selected steam trap lines due to flow accelerated corrosion and external general corrosion. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.10 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

The Intake Cooling Water System Inspection Program manages the aging effects of loss of material due to various corrosion mechanisms, and particulate and biological fouling for Intake Cooling Water (ICW) System components and the ICW side of the Component Cooling Water heat exchangers. The program includes inspections, performance testing, evaluations, and corrective actions that are performed as a result of FPL commitments in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

18.2.11 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of loss of material, cracking, loss of seal, and fouling (mechanical components only) for various plant systems, structures, and components. The scope of the program provides for visual examination of selected surfaces of specific systems, structures, and components. Additionally, the program provides for replacement/"refurbishment of selected components on a specified frequency, as appropriate, and periodic sampling and water removal from fuel oil storage tanks. The frequency of inspections varies depending on the specific component, the aging effect being managed, and plant operating experience.

Specific enhancements to the scope of this program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.12 REACTOR VESSEL INTEGRITY PROGRAM

The Reactor Vessel Integrity Program manages reactor vessel irradiation embrittlement and encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Program documentation will be enhanced to integrate aspects of the Reactor Vessel Integrity Program prior to the end of the initial operating license term for St. Lucie Unit 1.

18.2.12.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

This subprogram manages the aging effect of reduction in fracture toughness of the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens. The Reactor Vessel Surveillance Capsule Removal and Evaluation subprogram is an NRC-approved program that meets the requirements of 10 CFR 50, Appendix H. The surveillance capsule withdrawal schedule is specified in Table 5.4-3.

18.2.12.2 FLUENCE AND UNCERTAINTY CALCULATIONS

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates and welds.

18.2.12.3 MONITORING EFFECTIVE FULL POWER YEARS

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessel to ensure that the pressure-temperature limits and end-of-life reference temperatures are not exceeded.

18.2.12.4 PRESSURE-TEMPERATURE LIMIT CURVES

This subprogram provides pressure-temperature limit curves for the reactor vessel to establish the RCS operating limits. The pressure-temperature limit curves are included in the Technical Specifications.

18.2.13 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program is consistent with the guidelines provided by the Nuclear Energy Institute’s NEI 97-06, "Steam Generator Program Guidelines." The program ensures that steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The program manages the aging effects of cracking and loss of material.

18.2.14 SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling (for mechanical components only), loss of seal, and change in material properties. The program provides for periodic visual inspection and examination for degradation of accessible surfaces of specific systems, structures, and components, and corrective actions, as required, based on these inspections.

This program will be enhanced to provide guidance for managing the aging effects of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. These enhancements will be made prior to the end of the initial operating license term for St. Lucie Unit 1.

18.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

18.3.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The St. Lucie Unit 1 reactor vessel is described in Chapters 4 and 5. Time-limited aging analyses (TLAAs) applicable to the reactor vessel are:

- pressurized thermal shock
- upper-shelf energy
- pressure-temperature limits

The Reactor Vessel Integrity Program, described in Section 18.2.12, manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, Charpy upper-shelf energy, and pressure-temperature limits to ensure continuing vessel integrity through the period of extended operation.

18.3.1.1 PRESSURIZED THERMAL SHOCK

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility.

The calculated RT_{PTS} values that bound the 60-year period of operation for the St. Lucie Unit 1 reactor vessel are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the reactor vessel during the license renewal period.

The analysis associated with pressurized thermal shock 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).

18.3.1.2 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G, requires licensees to submit an analysis at least 3 years prior to the time that the USE of any reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing.

An evaluation was performed to demonstrate continued acceptable margins of safety against fracture through the end of the period of extended operation. All reactor vessel beltline material USE projections remain acceptably above the 10 CFR 50, Appendix G, limit of 50 ft-lbs at the end of the 60-year period of operation using a conservative bounding fluence.

The analysis associated with USE 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).

18.3.1.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, stipulate that heatup and cooldown of the reactor pressure vessel be accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within the limits of Appendix G defined by the reactor vessel fluence.

The heatup and cooldown pressure-temperature limits are presented in the Unit 1 Technical Specifications. The pressure-temperature curves will be updated as the operating schedule requires. In addition, low temperature overpressure protection (LTOP) requirements will be updated to ensure that the pressure-temperature limits are not exceeded for postulated plant transients.

The analyses associated with reactor vessel pressure-temperature limits for St. Lucie Unit 1 will be available prior to entering the period of extended operation, in accordance with the requirements of the Reactor Vessel Integrity Program and consistent with 10 CFR 54.21(c)(1)(ii).

18.3.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time-limited aging analyses for St. Lucie Unit 1. Specific components have been designed considering design cycle assumptions, as listed in vendor specifications and in Sections 3.9.2 and 5.2.1.2.

18.3.2.1 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 1 COMPONENTS

The reactor vessel (including control element drive mechanisms), reactor vessel internals, pressurizer, steam generators, and the reactor coolant pumps have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The reactor coolant piping was originally designed in accordance with ANSI B 31.7, "Nuclear Power Piping." The pressurizer surge line was reanalyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." These design codes require a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded.

Reactor vessel internals fatigue is addressed in Section 18.3.7.1.

Fatigue usage factors for critical locations in the St. Lucie Unit 1 Nuclear Steam Supply System Class 1 components were determined using design cycles that were specified in the plant design process or as a result of industry fatigue issues (e.g., thermal stratification). These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for the Class 1 components satisfying ASME fatigue usage design requirements.

Experience has shown that actual plant operation is often very conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the period of extended operation, the design cycles applicable to the Class 1 components were assembled.

The actual frequency of occurrence for the fatigue sensitive design cycles was determined and compared to the design cycle set. The severity of the actual plant cycles was also compared to the severity of the design cycles. These comparisons were performed in order to demonstrate that on an event-by-event basis the design cycle profiles envelope actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the Fatigue Monitoring Program. The reviews described above concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the structural integrity of the Class 1 components have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program.

18.3.2.2 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 2 AND 3 AND ANSI B31.1 COMPONENTS

St. Lucie Unit 1 has a number of piping systems within the scope of license renewal that were originally designed to the requirements of ANSI B31.7, Class 2 and 3, or ANSI B31.1, "Power Piping." Subsequently, piping systems originally designed to the requirements of ANSI B31.7, Class 2 and 3, were reconciled to ASME Section III, Class 2 and 3. Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to operations. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years.

A review of ASME Section III, Class 2 and 3, and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperatures. Based on industry guidance, any piping system with operating temperatures less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Under current plant operating practices, piping systems within the scope of license renewal are only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady-state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or for periodic testing. The review of applicable plant systems determined that, except for the RCS hot-leg sample piping, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. Therefore, the current piping analyses remain valid for the period of extended operation.

The RCS hot-leg sample lines could exceed the 7000 equivalent full temperature thermal cycles during the period of extended operation based on the current sampling practices. The sample piping and tubing were re-evaluated to consider the projected number of cycles and the analyses were found acceptable for the period of extended operation.

Except for the RCS hot-leg sample lines, the ASME Section III, Class 2 and 3, and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The RCS hot-leg sample lines' fatigue analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.3 ENVIRONMENTALLY ASSISTED FATIGUE

Generic Safety Issue (GSI) 190 was initiated by the NRC staff because of concerns about the potential effects of reactor water environments on RCS component fatigue life during the period of extended operation. The FPL approach to address reactor water environmental effects accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 60-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment.

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995, fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system (NSSS) vendors. The pressurized water reactor (PWR) calculations included in NUREG/CR-6260, especially for the "Older Vintage Combustion Engineering Plant," match St. Lucie relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the St. Lucie Unit 1 design.

Environmental fatigue calculations have been performed for St. Lucie Unit 1 for those component locations included in NUREG/CR-6260 using the appropriate methods contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998, or NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999, as appropriate. Based on these results, all component locations were determined to be acceptable for the period of extended operation, with the exception of the pressurizer surge line (specifically the surge line elbow below the pressurizer).

FPL has selected aging management to address pressurizer surge line fatigue during the period of extended operation, in lieu of performing additional analyses to refine the fatigue usage factors. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the extended period of operation by the continued performance of the St. Lucie ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program, as described in Section 18.2.2.1. Additionally, specific requirements will be included to evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue (see Section 18.2.2.1).

18.3.3 ENVIRONMENTAL QUALIFICATION

The thermal, radiation, and wear cycle aging analyses of plant electrical and I&C components have been identified as TLAAs for St. Lucie Unit 1. In particular, the environmental qualification evaluations of electrical equipment with a 40-year qualified life or greater have been determined to be TLAAs.

Equipment included in the St. Lucie Environmental Qualification Program has been evaluated to determine if existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment currently qualified at St. Lucie for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding their qualified lives in accordance with the Environmental Qualification Program, as described in Section 18.2.6.

Age-related service conditions that are applicable to the environmentally qualified equipment (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current environmental qualification analyses are bounding. The evaluations considered radiation, thermal, and wear cycle aging effects.

Therefore, the analyses associated with the environmental qualification of electrical equipment remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

18.3.4 CONTAINMENT PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I Those which must accommodate considerable thermal movements (hot penetrations)
- Type II Those which are not required to accommodate thermal movements (cold penetrations)
- Type III Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV Containment sump recirculation suction lines
- Type V Fuel transfer tube

The containment penetration bellows fatigue analyses have been evaluated and determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.3.5 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed Nuclear Steam Supply Systems (NSSS), which included St. Lucie Unit 1. The LBB analysis was performed to show that any potential leaks that develop in the RCS primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the RCS loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which covers the extended period of operation. Therefore, the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles are consistent with those utilized in the fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The RCS primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

18.3.6 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs:

- Reactor Building Polar Crane
- Intake Structure Bridge Crane
- Reactor Containment Building Auxiliary Telescoping Jib Crane

(Note: Fuel handling equipment does not require a TLAA evaluation because its lifting function is not in the scope of license renewal.)

The load cycles for these cranes were evaluated for the period of extended operation. For each crane, the actual usage over the projected life through the period of extended operation will be far less than the analyzed quantity of cycles. All the cranes in the scope of license renewal will continue to perform their intended function throughout the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, are valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

18.3.7 CORE SUPPORT BARREL

During the 1983 refueling outage, the reactor vessel internals core support barrel (CSB) and thermal shield assembly were observed to be damaged. The thermal shield was permanently removed and the CSB was repaired at the thermal shield support lug locations. Four lugs were separated from the CSB and through-wall cracks were adjacent to some damaged lug areas. Through-wall cracks were arrested with crack arrestor holes, non-through-wall cracks were machined out, and lug tear out areas were machined and patched as necessary. The crack arrestor holes were sealed by inserting expandable plugs.

Analysis of the CSB repair method was performed by the NSSS supplier to demonstrate 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.

The analyses and follow-up inspection reports for the repaired CSB and the expandable plugs were screened against the six TLAA criteria. It was determined that two specific elements of the repair qualify as TLAAs: 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plugs' preload based on irradiation-induced stress relaxation.

18.3.7.1 CORE SUPPORT BARREL FATIGUE ANALYSIS

As discussed in Section 18.3.2.1, the 40-year design cycles bound the extended period of operation. Therefore the CSB fatigue analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

18.3.7.2 CORE SUPPORT BARREL REPAIR PLUG ANALYSIS

The repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB. 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 original evaluation of plug design preload verified that the design preload was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant.

The original CSB plug preload analysis was revised for increased fluence (60-year period of operation) and 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' preload. The CSB repair plugs will therefore perform their intended function for the period of extended plant operation.

The CSB preload stress 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).

18.3.8 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

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 primary water stress corrosion cracking. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

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" weld were bounded by the fracture mechanics analysis provided in Combustion Engineering Owner's Group (CEOG) Topical Report CE NPSD-1198-P.

CEOG Topical Report CE NPSD-1198-P was submitted to the NRC February 15, 2001 to obtain generic approval of the Alloy 600/690 nozzle repair/replacement programs. The CEOG report provides a bounding flaw evaluation that covers all small diameter Alloy 600/690 nozzle repairs in accordance with ASME Section XI requirements. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 1 UFSAR. This generic analysis bounds the Class 1 fatigue design requirements of St. Lucie Unit 1. As discussed in Section 18.3.2.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The flaw growth analysis of the Unit 1 RCS hot-leg Alloy 600 instrument nozzle repair has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

APPENDIX A2

UNIT 2 UPDATED FSAR SUPPLEMENT

INTRODUCTION

This Appendix contains the St. Lucie Unit 2 UFSAR Supplement required by 10 CFR 54.21(d). The St. Lucie LRA contains the technical information required by 10 CFR 54.21(a) and (c). Chapter 3 and Appendix B of the LRA provide descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Chapter 4 of the LRA contains the evaluations of the time-limited aging analyses (TLAAs) for the period of extended operation. These LRA sections have been used to prepare the program and activity descriptions that are contained in the UFSAR Supplement.

This UFSAR Supplement will be incorporated into the St. Lucie Unit 2 UFSAR following issuance of the renewed operating license for St. Lucie Unit 2. Upon inclusion of the UFSAR Supplement in the St. Lucie Unit 2 UFSAR, changes to the descriptions of the programs and activities for their implementation will be made in accordance with 10 CFR 50.59 and St. Lucie Plant's NRC commitment management program.

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CHAPTER 1 CHANGES

The tubes are fabricated into assemblies in which end fittings prevent axial motion and spacer grids prevent lateral motion of the tubes. Beginning with Region N, the fuel incorporates the GUARDIAN^{TM} fuel assembly design to screen and entrap debris. The GUARDIAN^{TM} design employs a redesigned bottom spacer grid that provides positive axial restraint to the rods and added screening features. Region N also includes the addition of "backup arches" adjacent to all cantilevered springs in the interior of the upper H1D-1L spacer grid. The backup arch limits the possible compression of the grid spring, and thereby better maintains the proper geometry between the grid support features and the fuel rod during fabrication and operation. This same feature was present in peripheral locations in each Zircaloy spacer grid for all previous St. Lucie 2 fuel batches. In these locations, the backup arches protect the grid springs that may be subject to compression during fuel handling, when peripheral fuel rods can be pressed inward as bowed fuel assemblies are slid past one another in the core. In the new upper grid design, the arches will be present at all 440 interior spring locations in the grid. The backup arches will thus limit compression of grid springs in all interior locations during fuel rod loading.The control element assemblies (CEAs) consist of inconel clad boron carbide absorber rods which are guided by zircaloy tubes located within the fuel assembly. The core consists of 217 fuel assemblies with three U-235 enrichments in a three batch, mixed central zone arrangement.

Minimum departure from nucleate boiling ratio (DNBR) during normal operation and anticipated operational occurrences is not less than 1.28 (cycle 1 was 1.19) using the CE-1 correlation. The maximum center line temperature of the fuel, evaluated at the design overpower condition, is below that value which could lead to fuel rod failure. The melting points of the UO2 and UO_2-Gd_2O_3 and/or UO_2-Er_2O_3 are not reached during routine operation and anticipated operational occurrences.

The combined response of the fuel temperature coefficient, the moderator temperature coefficient, the moderator void coefficient and the moderator pressure coefficient to an increase in reactor thermal power is a decrease in reactivity. In addition, the reactor power transient remains bounded and damped in response to any expected changes in any operating variable.

Control element assemblies (CEAs) are capable of holding the core sub-critical at hot zero power conditions with margin following a trip even with the most reactive CEA stuck in the fully withdrawn position.

Fuel rod clad is designed to maintain cladding integrity throughout fuel life. Fission gas release within the rods and other factors affecting design life are considered for the maximum expected exposures.

The reactor and control systems are designed so that any xenon transients are adequately damped.

The reactor in conjunction with the Reactor Protective System is designed to accommodate safely and without fuel damage, the anticipated operational occurrences.

The reactor vessel and its closure head are fabricated from manganese molybdenum nickel steel internally clad with austenitic stainless steel. The vessel and its internals are designed so that the integrated neutron flux does not exceed ~~3.2~~ 4.9 x 10^{19} n/cm^2 (E > 1 Mev) over the ~~40~~ 60-year design life of the vessel.

Power excursions which could result from any credible reactivity addition do not cause damage, either by deformation or rupture of the reactor vessel and do not impair operation of the Engineered Safety Features.

The internal structures include the core support barrel, the lower support structure, the core shroud, the hold-down ring and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. ~~m e~~The lower support structure transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and limits the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are

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2.5.2.7.1 Earthquake Frequency Analysis

The probability of a seismic event equaling or exceeding the OBE was computed using standard statistical methods. The region surrounding the site was subdivided into areas of similar seismicity (see Subsection 2.5.2.3 and Figure 2.5-32) and the statistical properties of seismic events were developed for each area. The effects of events in neighboring provinces were attenuated to the site. The annual probability of events of each intensity greater than or equal to V MM at the site was computed. Horizontal accelerations for each intensity were taken from the 1975 Trifunac-Brady relationship. The annual probability for an event greater than or equal to .05g was interpolated from the results of this computation, and the probability of occurrence of one or more such events was computed. The results of these computations indicated a probability of occurrence of this event of ~~1.3~~ approximately 2 percent over the ~~40~~ 60-year life of the plant, or about once per 3,000 years.

2.5.3 SURFACE FAULTING

2.5.3.1 Geologic Conditions of the Site

The geologic conditions of the site and surrounding area have been described in the Subsections 2.5.1.1 and 2.5.1.2. Geologic structure and hypothesized faulting in the region have been discussed in Subsection 2.5.1.1.4. It is concluded that no seismic generative faults exist within 200 miles of the site. Figure 2.5-8 shows the locations of hypothesized faulting within peninsular Florida.

2.5.3.2 Evidence or Absence of Fault Offset

No specific detailed reports on the geology and groundwater resources of St Lucie County have been published; however, geologic studies have been reported for Martin County to the south[2] and Indian River[1] and Brevard[39] Counties to the north. Figure 2.5-27 is a map showing all hypothesized structures in the three county area.

2.5.3.2.1 Hypothesized Faulting in Indian River County

Bermes[1] utilized data from wells drilled into Eocene strata to develop geologic sections in Indian River County. These sections indicated Eocene and Miocene strata sloped gently to the southeast in most of the county. Bermes reported an apparent change in dip from less than five ft. per mile to greater than 70 ft. per mile and the occurrence of Oligocene age beds near the eastern margin of the county. He postulates a somewhat complex system of three high-angle, normal faults essentially parallel to the coastline (see Figure 2.5-27) to explain the steepening dip and the occurrence and apparent thickening in Oligocene strata to the east. Strata on the east side of the faults were projected to be downthrown. The faults were postulated based on elevation differences of about 225 ft. in the top of the Ocala group over a horizontal distance of about 2.5 miles. He did not discuss the age of the faulting, but the fault traces shown in his geologic sections terminated at the base of Miocene strata, indicating an age of last movement of at least 20 million years.

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In case of a rupture of the process pipe in the annulus area, the guard pipe acts to direct the fluid back into the containment vessel, thus preventing overpressurization of the annulus. The penetration is designed to accommodate all forces and moments due to both thermal expansion and pipe rupture.

d) Containment Sump Recirculation Suction Lines

A special type of penetration assembly (Type IV) is provided for the suction lines from the containment sump. These lines are used following a LOCA to allow recirculation of containment sump water by the containment spray and high pressure safety injection pumps.

As shown on Figure 3.8-6, each line consists of a double barrier concentric pipe from the sump up to the suction line isolation valve outside the containment. The penetration assembly is designed for the differential motion associated with the SSE.

e) Fuel Transfer Tube Penetration

A fuel transfer tube penetration (Type V) is provided to transport fuel rods between the refueling transfer canal and the spent fuel pool during refueling operations of the reactor. The penetration is shown on Figure 3.8-7 and consists of a 36 in. diameter stainless steel pipe installed inside a 48 in. pipe. The inner pipe acts as the transfer tube and is fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the Reactor Building and the Fuel Handling Building.

The bellows expansion joints which form a part of the containment boundary meet the requirements of ASME Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water.

Bellows design and construction is such that the bellows does not deflect more than its designed amount: The bellows is designed to withstand a ~~40~~ 60-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion.

f) Containment Vacuum Breaker Penetration

The penetration consists of a nozzle welded on the containment vessel with a check valve inside the containment and a butterfly valve outside the containment (see Figure 3.8-8).

The containment vessel penetration details are shown on Figures 3.8-9, 3.8-10 and 3.8-11. Shield Building penetration details are shown on Figure 3.8-9.

and safety are involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities.

Test (T) - Test conditions are those tests in addition to the 10 hydrostatic or pneumatic tests permitted by ASME Code, Section III, including leak tests or subsequent hydrostatic tests.

The appropriate loading combination and stress limits for each of the above conditions are discussed in Subsection 3.9.3.1.

In support of the design of each Quality Group A component, a fatigue analysis of the combined effects of mechanical and thermal loads is performed in accordance with the requirements of ASME Code, Section III. The purpose of the analysis is to demonstrate that fatigue failure does not occur when the components are subjected to typical dynamic events which may occur in the power plant.

The fatigue analysis is based upon a series of dynamic events depicted in the respective component specifications. Associated with each dynamic event is a mechanical, thermal-hydraulic transient presentation along with an assumed number of occurrences for the event. The presentation is generally simple and straightforward, since it is meant to envelop the actual plant response. The intent is to present material for purposes of design. A best-estimate representation of the expected plant dynamic response is neither intended nor appropriate. The fundamental concept is to ensure that the consequences of the normal and upset conditions which are expected to occur in the power plant are enveloped by one or more of the dynamic event portrayals in the component specifications. The number of occurrences selected for each dynamic event is considered to be conservative, so that in the aggregate a ~~40~~ 60-year useful life is provided by this design process.

A stress analysis is performed on Quality Group A piping in accordance with the ASME Code, Section III, 1971 edition and all addenda up to and including Summer 1973 addenda. A stress report is developed in accordance with Section NB of ASME Code, Section III. The Quality Group A piping is listed in Table 3.9-1.

The Quality Group A components listed in Table 3.9-1 are analyzed with the appropriate loading combinations of pressure, temperature and flow transients for the normal, upset, emergency, faulted and test conditions. Design load combinations and stress limits for the above components are given in Subsection 3.9.3.

Quality Group A piping is classified as seismic Category I and is analyzed as such. The operating basis earthquake (OBE) loading is considered to occur five times over the plant life with 40 cycles for each event. One safe shutdown earthquake (SSE) event is assumed to occur for Quality Group A piping for the life of the plant.

The ASME Quality Group A valves are designed in accordance with Article NB-3000 of ASME Code, Section III. The Quality Group A valves are as listed in Table 3.9-1. When required by ASME Code, Section III the Quality Group

3.9.3 ASME CODE CLASS 1, 2 and 3 COMPONENTS, COMPONENT SUPPORTS AND CORE SUPPORT STRUCTURES

3.9.3.1 LOADING COMBINATIONS, DESIGN TRANSIENTS AND STRESS LIMITS

ASME Code Class 1, 2 and 3 system components are designed in accordance with the rules and methods specified in the ASME code. The design stress limits of the ASME Code (including code cases) are selected to insure the pressure retaining integrity of safety class equipment. Code cases utilized by the A/E have been approved by Regulatory Guide 1.84 "Design and Fabrication Code Case Acceptability" (R9) and 1.85 "Material Code Cases utilized by the NSSS Vendor" (R9) is discussed in FSAR Section 5.2.

Design transients for ASME Code Class 1 components are provided in Table 3.9-3, Stress limits for A/E Supplied Class 1 components are described in Subsection 3.9.3,1,1. The stress limits and loading combinations for NSSS Supplied Class 1, 2, and 3 components are described in Subsection 3.9.3.1.3.

ASME Code Class 2 and 3 components are designed for the concurrent loadings produced by pressure, deadweight, temperature distributions, the vibratory motion of the safe shutdown earthquake (SSE), and the dynamic system loadings associated with the appropriate plant faulted condition. The design loading combinations for specific plant operating conditions are listed in Table 3.9-5. Additionally, an investigation was performed for all Safety Class 2 and 3 piping systems (irrespective of operating temperature) to demonstrate that the number of equivalent thermal cycles, as defined in ASME Subsection NC 3611.2, was sufficiently low to confirm the conservatism of the existing stress analyses.

In accordance with the agreement reached at a meeting with the NRC and Florida Power & Light Company on October 14, 1982 an acceptance criteria of 1000 "Realistic" cycles was employed. In conducting this analysis, the following Safety Class 2 and 3 systems were reviewed:

Reactor Coolant	Component Cooling Water
Charging	Letdown
Safety Injection	Auxiliary Feedwater
Main Steam	Containment Spray
Main Feedwater	Intake Cooling Water

A sample calculation specifying methodology and a summary of the results is provided in Table 3.9-5b.

Using realistic values of cycle frequencies, all systems were shown to exhibit approximately 700 equivalent cycles. Using all the thermal transients that appear in the Safety Class 1 specification (Refer to Table 3.9-5b), which is conservative both in frequency and temperature variation, all systems were shown to have less than 1000 equivalent thermal cycles. Therefore, the above results confirm the conservatism of the existing stress analyses for Class 2 and 3 systems and was approved by the NRC (NUREG-0843 Supplement 3, April 1983).

Class 2 and 3 piping systems were reviewed for thermal fatigue and confirmed to be acceptable for 60 years of operation. See Section 18.3.2.2.

3.9.4 CONTROL ELEMENT DRIVE MECHANISMS

3.9.4.1 Descriptive Information of CEDM

The control element drive mechanism (CEDMs) are magnetic jack type drives used to vertically position and indicate the position of the control element assemblies (CEAs) and the part-length control element assemblies (PLCEAs) in the core. Each CEDM is capable of withdrawing, inserting, holding, or tripping the CEA/PLCEA from any point within its 137 inch stroke in response to operation signals.

The CEDM is designed to function during and after all normal plant transients. The design life of the CEDM is defined as ~~40~~ 60 years of operation or 100,000 feet of rod travel without loss of function. The CEDM is designed to operate without maintenance for a minimum of 1-1/2 years and without replacing components for a minimum of three years. The CEDM is designed to function normally during and after being subjected to the operating basis earthquake loads. The CEDM allows for tripping and drive-in of the CEA/PLCEA during and after a safe shutdown earthquake.

The design and construction of the CEDM pressure housings fulfill the requirements of the ASME Code, Section III, Class 1. The CEDM pressure housings are part of the reactor coolant pressure boundary, and they are designed to meet stress requirements consistent with those of the vessel. The pressure housings are capable of withstanding, throughout the design life, all normal operating loads, which include the steady-state and transient operating conditions specified for the vessel. Mechanical excitations are also defined and included as a normal operating load. The CEDM pressure housings are service rated at 2500 psia and 650°F. The loading combinations and stress limit categories are presented in Subsection 3.9.4.3 and are consistent with those defined in the ASME Code.

The test programs performed in support of the CEDM design are described in Subsection 3.9.4.4.

3.9.4.1.1 Control Element Drive Mechanism Design Description

The CEDMs are mounted and seal welded on nozzles on top of the reactor vessel closure head. The CEDMs consist of the upper and lower CEDM pressure housings, motor assembly, coil stack assembly, reed switch assemblies, and extension shaft assembly. The CEDM is shown on Figure 3.9-11. The drive power is supplied by the coil stack assembly, which is positioned around the CEDM housing. A position indicating reed switch assembly is supported by the upper pressure housing shroud, which encloses the upper pressure housing assembly.

The components outside the pressure boundaries are the coil stack, the pressure housing shroud, and the cooling shroud. All are designed to be a slip fit over the motor housing and are capable of being removed at temperature. A test was performed to verify this requirement. Dimensions and materials used for the St. Lucie 2 CEDMs are identical to those on operating reactors.

TABLE 3.9-2

TRANSIENTS USED IN DESIGN AND FATIGUE ANALYSIS

NOTE: Class 1 piping and components were reviewed for thermal fatigue and were confirmed to be acceptable for 60 years of operation, utilizing the original 40-year design cycles. See Section 18.3.2.1.

1. Normal Conditions

(a) 500 heatup and cooldown cycles during the design life of the components with heating and cooling at a rate of 100ºF/hr between 70ºF and 532ºF (653ºF for the pressurizer). The heatup and cooldown rate of the system is administratively limited to 75ºF/hr to assure that these limits will not be exceeded. This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred.

(b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

(c) 2,000 cycles of step power changes of 10 percent of full load, increasing in the 15 percent to 100 percent of full load range and decreasing in the 100 percent to 25 percent of full load range. This is based on a normal plant operation involving one cycle per week for 50 weeks of the year.

(d) 1×10^6 cycles of normal variations of - 100 psi and – 6ºF when at operating temperature and pressure. This was selected based on 1 x 10 cycles being equivalent to infinite cycles and thus the limiting stress is the endurance limit. - 100 psi is the maximum pressure fluctuation above the setpoint (2235 psig) before backup heaters come on or spray valves open. For conservatism, the temperature cycle developed for the pressurizer is used for all components.

2. Upset Conditions

(a) 40 cycles of complete loss of reactor coolant flow when at 100 percent power. This is based on one reactor trip per year for the life of the plant resulting from failure of electrical supply to the reactor coolant pumps.

(b) 400 reactor trips from full load. This is based on one reactor trip per month for the life of the plant and includes trips due to operator error and equipment failure.

(c) 40 cycles of turbine trip from 100 percent power with delayed reactor trip. This is based on one reactor trip per year for the life of the plant considering failure of the turbine trip/ reactor trip circuit as credible.

TABLE 3.9-3A

A/E SUPPLIED QUALITY GROUP A TRANSIENTS

PLANT EVENT	LIFETIME OCCURRENCES	COMPONENT* CONDITION
Plant Cooldown	500	N
Plant H~~h~~eatup	500	N
Power Operation	-	N
Loading/Unloading Ramp 5% per Min Step 10%	 15,000 2,000	
Reactor Trip	400	U
Hydro Static Tests, (3125 psia)	10	T
Leak Test, (2250 psia)	200	T
Normal Pressure Variation ($\pm$ 100 psi, $\pm$ 7^o F)	10^6	N
Loss of Primary Flow	40	U
Loss of Secondary Pressure	5	E
Loss of Turbine-Gen. Load	40	U
Purification, & Boron Dilution (CVCS)	24,000	N
Loss of Charging Flow (CVCS)	~~20~~ 100	U
Regenerative Heat Exchanger Isolation and Loss of Letdown (CVCS)	~~50~~ 270	U
Isolation Check Valve Leaks	40	U

*Definitions of the events Normal (N), Upset (U), Emergency (E), Faulted (F) and Test (T) are given in ASME III, Para. NB-3113.

3.9-65 Amendment No. ~~12 (12/98)~~ [LATER]

b) Non safety electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified previously.

c) Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 3, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident."

These components are identified and controlled on plant drawing 2998-A-450.

3.11.4 QUALIFICATION OF COMPONENTS

If the equipment in question meets the requirement found in Subsection 3.11.3, it must be qualified to 10CFR.50.49. The "Environmental Qualification Report and Guidebook," Drawing 2998-A-451-1000 provides the information required to properly identify the environment to which the specific equipment must be qualified. Operability requirements associated with the component are discussed along with the required temperature, pressure, humidity, radiation, aging and submergence.

Each parameter is defined in a specific subsection. Most parameters are identified on Zone Maps as a convenient reference. Zone Maps indicate the normal and abnormal values associated with specific areas of the plant at a given period of time.

Harsh environments are characterized by abnormally high temperatures and pressures, high radiation doses, corrosive chemical spray, and/or high relative humidity. Also, in some cases, submergence may have to be considered based on equipment location with respect to the maximum flood level.

A mild environment, as defined in 10CFR50.49, is an environment that would at no time be significantly more severe than the environment which would occur during normal operation, including operational occurrences. Equipment located in a mild environment is not covered under 10CFR50.49. Mild environments operability is assured by either: (a) periodic maintenance, inspection and/or a replacement program based on sound engineering judgement or manufacturer's recommendations; (b) a periodic testing program; (c) an equipment surveillance program.

Environments in which radiation is the only parameter of concern are considered to be mild if the total radiation dose (includes ~~40~~ 60-year normal dose plus the post accident dose) is 1.0E5 rads or less. This value is the threshold for evaluation and consideration. Excluded from this consideration, however, are most solid state electronic components and components that utilize teflon. Class IE equipment located in environments between 1.0E3 and 1.0E5 are evaluated on a case by case basis.

For additional detail on the identification of environmental conditions refer to Drawing 2998-A-451-1000," Environmental Qualification Report and Guidebook."

3.11-4 Amendment No ~~3 (4/88)~~ [LATER]

3.11.5 MAINTENANCE

The purpose of the St. Lucie Unit 2 Equipment Qualification Program is the preservation of the qualification of safety related systems, structures and components. In order to accomplish the task, the plant has developed approved Design Control, Procurement and Maintenance Procedures. Each procedure has incorporated the requirements of environmental qualification according to the functional requirements of the program/system/component. The plants procedures are prepared to maintain proper design control, for plant modifications, procurement of new equipment and spare parts. The plants maintenance program is designed to provide preventative as well as corrective maintenance which is identified by field operational experience and industry correspondence. In addition, the component specific documentation package contains, in Section 5, the equipments qualified life. This qualification interval is developed based upon the vendors test report reviewed in conjunction with the environmental parameter associated with the area. After this review is completed a qualified life is established and operation with this piece of equipment up to the equipments end point is acceptable.

3.11.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturers piece of equipment under the auspices of 10CFR50.49. This package contains the information, analysis and justifications necessary to demonstrate that the equipment is properly and validly qualified for the environmental effects of ~~40~~ 60 years of service plus a design basis accident.

This documentation package is developed from the criteria stipulated in the Environment Qualification Report and Guidebook.

A complete listing of equipment under the auspices of 10CFR50.49 is maintained.

All three of the above documents are drawings and are developed and controlled under the procedures involving drawing preparation, updating and storage as specified in the FPL Quality Assurance Program.

The generic elements of the FPL Quality Assurance Program are described in the Florida Power and Light Topical Quality Assurance Report (FPLTQAR). The FPLTQAR defines departmental responsibilities by which FPL implements the corporate Quality Assurance program, and is an integral part of the corporate Quality Assurance Manual.

3.11.7 CONCLUSIONS

The Equipment Qualifications Report and Guidebook, together with the manufacturers' specific Documentation Packages and the 10CFR50.49 list of equipment have been developed for the purpose of documenting the environmental qualification of safety related equipment. This program has insured the systems selected for qualification are complete, the environmental conditions resulting from the design basis accident are indentified and that the methods used for qualification are appropriate.

Based on these checks and the ongoing environmental qualification program, St. Lucie Unit 2 is in compliance with 10CFR50.49.

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4.3.2.8 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that for reactor operation at the full power rating and an 80 percent capacity factor, the vessel fluence greater than one MeV at the vessel wall will not exceed 4.9 ~~3.66~~ x 10^{19} n/cm^2 over the ~~40~~ 60-year design life of the vessel. The calculated exposure includes a 10 percent uncertainty factor.

The maximum fast neutron fluxes greater than one MeV incident on the vessel ID and shroud ID are as shown in Table 4.3-10. The fluxes are based on a time averaged equilibrium cycle radial power distribution and an axial power distribution with a peak to average of 1.20. The calculation assumed a thermal power of 2700 MWt. The models used in these calculations are discussed in Subsection 4.3.3.3.

4.3.3 ANALYTICAL METHODS

Discussions of methodologies within this section are written from an historic perspective and may have been superseded by newer methods as discussed in Reference 65.

Beginning with Cycle 12, Westinghouse physics methodology is used to generate physics inputs and characteristics based on Reference 69.

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis (HISTORICAL)

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include spatial effects in those portions of the neutron energy spectrum where volume homogenization is inappropriate; e.g., the thermal neutron energy range. Most of the calculations are performed with the aid of computer programs embodying analytical procedures and fundamental nuclear data consistent with the current state of the art.

Comparisons between calculated and measured data that validate the design procedures are presented in Subsection 4.3.3.1.2. As improvements in analytical procedures are developed, and improved nuclear data become available, they will be added to the design procedures, but only after validation by comparison with related experimental data.

Few group cross sections for subregions of the core that are represented in spatial diffusion theory codes, e.g., fuel pin cells, moderator channels, structural member cells, etc., are calculated by the CEPAK lattice program. This program is the synthesis of a number of computer codes, many which were developed elsewhere; e.g., FORM,[3] THERMOS[4] and CINDER.[5] These programs are interlinked in a consistent way with inputs from differential cross-section data from an extensive library.

The microscopic data base for both fast and thermal neutron cross-section is derived from the Evaluated Nuclear Data File ENDF/B-IV. Some modifications have been applied to the U-238 resonance integral to correct for a recognized overestimation of that quantity in ENDF/B-IV.

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TABLE 5.3-9

CAPSULE ASSEMBLY REMOVAL SCHEDULE[(e)]

~~Capsule No.~~	~~Azimuthal~~ Location on Vessel Wall	Approximate Removal Time (EFPY)	Predicted Fluence (n/cm^2)	Lead Factor[(d)]
~~1~~	83°	1.11 [(a)]	1.779×10^{18}	~~≤1.5~~ ------
~~2~~	97°	~~24~~ 26	2.70×10^{19}	~~≤1.5~~ 1.27
~~3~~	104°	Standby[(c)]	------	~~≤1.5~~ 0.98
~~4~~	263°	11[(b)]	1.244×10^{19}	~~≤1.5~~ ------
~~5~~	277°	44/Standby[(c)]	4.56×10^{19}	~~≤1.5~~ 1.27
~~6~~	284°	Standby[(c)]	------	~~≤1.5~~ 0.98

a. Actual removal time (Reference 5- Babcock & Wilcox Report # BAW-1880, Sept. 1985).

b. Actual removal time (Reference 6- Westinghouse Report # WCAP-15040, April 1998).

c. As required by ASTM E185, ~~O~~one standby capsule will be removed at the end of license fluence and available for testing. ~~per ASTM E185-82~~.

d. Lead Factor is defined as the capsule fluence/RV base metal peak fluence (Reference 6).

e. Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

5.3-27 Amendment No. ~~12 (12/98)~~ [LATER]

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requires that the radiolytic and pyrolytic characteristics of the protective coatings are tested, analyzed, and certified, in accordance with the above ANSI Standards, that no decomposition products will be released such as to interfere with the safe operation of any engineered safety feature. The physical-chemical characteristics of the above protective coatings are ensured by tests, conducted per ANSI Standards N512 and N101.2, to show that combustible properties are at or below the acceptable level delineated in those ANSI Standards. Tests deemed necessary to demonstrate satisfactory performance have been conducted.

Application of field applied coatings is done in compliance with the recommendations of each product manufacturer and per approved site-coating procedures. Quality assurance during manufacturing, storage, application and inspection of field applied coatings meets the intent of ANSI Standard N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," Nov. 1972, in conjunction with the general QA requirements of ANSI N45.2, Oct. 1971, and thereby are consistent with the requirements of Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water Cooled Nuclear Power Plants" June 1973.

Protective coatings ~~are~~ were originally intended for a 40 year service life. Consistent with St. Lucie's response to NRC Generic Letter 98-04 (see Section 6.3.2.2.2a), visual inspections and condition assessments of Service Level 1 coatings inside the containment building are performed every refueling outage. In the event that recoating is desired, the original coating is removed before application of any new coating. Note that coating parameters (i.e., thermal conductivity, thickness and volumetric heat capacity) are used in the accident analysis of Section 6.2.1.

The total amount of protective coatings and organic materials used inside the containment that do not meet the requirements of ANSI N101.2 (1972) and Regulatory Guide 1.54 is approximately 6 cubic feet. The amount of unqualified protective coatings is about 2.5 cubic feet. The equipment so coated is located in various parts of the containment. Although these coating schemes have not undergone DBA qualification testing, some of these coating schemes are baked on enamel which will not readily peel off under DBA environments. The remaining unqualified organic material is NUKEM 750 caulking material used as expansion joint filler (2.5 cubic feet) and miscellaneous organics (approximately 1 cubic foot). Use of NUKEM 750 was justified and was deemed acceptable by the NRC. [(1),(2)]

Evaluation of the effect of unqualified materials inside containment on combustible gas generation can be found in Subsection 6.2.5 and on ECCS sump screen design in Subsection 6.2.2.

6.1-10 Amendment No. ~~13, (05/00)~~ [LATER]

In addition to the redundant CGCS, the Continuous Containment Purge/hydrogen Purge System is available for fission product removal and hydrogen purge following a LOCA.

6.2.5.2 System Design

6.2.5.2.1 Containment Hydrogen Analyzer Subsystem

The Containment Hydrogen Analyzer System consists of two redundant subsystems as shown on Figure 6.2-62, consisting of the sample and return piping, associated valves, hydrogen analyzer, grab sample cylinder, sample pump, moisture separator, cooler, instruments, calibration gas line and reagent gas line.

Each of the redundant subsystems is physically separate and operates independently of the other, and is powered from an independent onsite power source. No single failure can result in a total loss of hydrogen concentration measurement capability. Failure of one train is annunciated in the control room.

Components of the system are accessible for periodic inspection and maintenance. The system is designed to permit remote calibration at periodic intervals with a reference hydrogen gas standard (span gas) and oxygen. The system is independent of any system used during normal plant operation so that plant operation does not impose restrictions on such testing.

The Hydrogen Analyzer System piping, from the sample points within the Containment and piping returning the sample to the Containment, up to and including all containment isolation valves, are designed and fabricated in accordance with ASME Section III Class 2 and N-stamped. The hydrogen analyzer package contains instrumentation elements which are inherently non-ASME, code items (e.g., flowmeters, pressure gages, and the analyzer element). Therefore, the hydrogen analyzer package is classified as a Class IE instrument. Instrumentation, controls and electric equipment associated with the system will be Class IE. Conformance to applicable IEEE Standards is discussed in Chapter 7.

The system is initiated by manual operator action from the control room. No action outside the control room is necessary for system operation.

Once initiated, the system draws a continuous air sample from one of the sample points inside containment. Sampling valves can be manually controlled to analyze any sample point. The air is passed through the detector, analyzed, and pumped back into containment. Analyzer readings are recorded in the control room, and an alarm is actuated if concentration is above three percent. Alarm is also provided for low flow and low temperature in the analyzer hot box. Design and performance date for the analyzer is listed in Table 6.2-54.

The system is designed ~~for 40 years of normal and one year post-LOCA environmental condition~~ and the components are qualified to operate under the applicable environmental conditions as described in Section 3.11.

tainment fan coolers and their associated ductwork as discussed in Subsection 6.2.2.2.2 by the turbulence introduced by the containment sprays, and by the process of natural diffusion of combustible gas with the containment air. Air is drawn into the recombiner by natural convection and passes first through the preheater section. This section consists of a shroud placed around the central heater section to take advantage of heat conduction through the walls to preheat the incoming air. This accomplishes the dual functions of reducing heat losses from the recombiner and of preheating the air.

The warmed air passes through an orifice plate and then enters the electric heater section where it is heated to approximately 1150ºF to 1400ºF causing recombination to occur. The flow then enters the cooling/exhausting section where the stream is mixed and diluted with cooler containment air in order to discharge the stream back into the containment atmosphere at a lower temperature.

Each hydrogen recombiner system has a removal capacity which is sufficient to limit concentrations of gases within the containment to safe concentrations; i.e., concentrations below the flammability limits. After a threehour startup period, the recombiner efficiency is 99-100 percent and the effluent does not exceed 100 F above ambient.

The unit is manufactured primarily of corrosion-resistant, high-temperature material for major structural components, except for the base which is steel. The electric hydrogen recombiner used conventional type electric resistance heaters sheathed with Incoloy-800 which is an excellent corrosion resistant material for this service. These heaters are designed to operate with sheath temperatures equal to those used in certain commercial heaters; however, these recombiner heaters operate at significantly lower power densities than in commercial practice.

The recombiners are located on the elevation 62.0 ft. of the containment. They are inaccessible following a LOCA, and as such there is no sharing of recombiners among St Lucie Units 1 and 2 or with other facilities. The hydrogen recombiners are designed for ~~40~~ 60 years normal and one year post LOCA conditions. Design and performance data for the recombiners are listed in Table 6.2-55.

Each of the two recombiners is 100 percent capacity, and is connected to a separate onsite power source so that no single failure results in a total loss of recombiner function.

The recombiner is started by the operator by manual action from the control room. The operator is alerted when the containment H_2 level reaches three volume percent as signaled by the redundant Class IE alarms of the Containment Hydrogen Analyzer System. Plant procedures provide guidance to the operator on when to start the hydrogen recombiner following a LOCA.

6.2.5.2.3 Containment Hydrogen Purge System

The Continuous Containment Purge/Hydrogen Purge System is provided as a further possible means of controlling hydrogen inside the containment following a LOCA. This system is provided as required by the NRC, although no single failure following a LOCA would necessitate its use. Therefore, the system

6.2-65 Amendment No. ~~11, (5/97)~~ [LATER]

6.3.2.2.3 High Pressure Safety Injection Pumps

The primary function of a high-pressure safety injection (HPSI) pump is to inject borated water into the Reactor Coolant System if a break occurs in the Reactor Coolant System boundary. For small pipe breaks, the Reactor Coolant System pressure remains high for a long period of time following the accident, and the high pressure safety injection pumps ensure that the injected flow is sufficient to meet the criteria given in Subsection 6.3.1. The high-pressure safety injection pumps are also used during the recirculation mode to maintain a borated water cover over the core for extended periods of time. For long term core cooling, the HPSI pumps are manually realigned for simultaneous hot and cold leg injection. This insures flushing and ultimate subcooling of the core coolant independent of break location. For small pipe breaks, the HPSI pumps continue injecting into the Reactor Coolant System to provide makeup for spillage out the break while a normal cooldown is implemented.

The St. Lucie 2 HPSI pumps are manufactured by Bingham-Willamette Company. These pumps are similar in design to conventional boiler feed pumps where continuous service over a broad range of temperature is required. Specific long-term testing of the HPSI pumps was not required because of the vendors experience with the design.

~~The St Lucie 2 HPSI pumps have a design lifetime of 40 years, consistent with the plant design basis.~~ Operational testing is considered as part of the functional requirements of the pump. For the purpose of pump specification and design, the long-term LOCA requirement is defined as continuous operation for up to one year at runout conditions. The operational experience of the pump vendor on similar equipment is defined below.

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h) Primary System Pressure Deviation

The assignment of an initiating event to one of these eight event types is made by collecting initiating events with the same major effect and similar occurrence rates into an Event Group. Each Event Group is then assigned to one of the above eight event types based on its primary impact on the NSSS. Table 15.0-1 lists all of the Event Groups and initiating events considered in the St Lucie Unit 2 accident analysis.

15.0.1.3 Frequency Groups

The five frequency groups used in the type/frequency matrix are listed below:

a) Moderate Frequency Event

A Moderate Frequency event may occur during a calendar year for a particular plant. ~~It is assumed that a Moderate Frequency event has at least a 50 percent probability of occurring in any calendar year for a particular plant.~~

b) Infrequent Event

An Infrequent event may occur during the lifetime of a particular plant. ~~It is assumed that an Infrequent event has less than a 50 percent probability of occurring in any calendar year, but at least a 50 percent probability of occurring in the assumed 40 year lifetime for a particular plant.~~

c) Limiting Fault

A Limiting Fault is not expected to occur during the lifetime of a particular plant. ~~It is assumed that a Limiting Fault has less than a 50 percent probability of occurring in the assumed 40 year plant lifetime, but at least a 10^{-6} probability of occurring in any calendar year.~~ This broad frequency group is divided into three subgroups to allow comparison of events with similar frequencies. These three subgroups of Limiting Faults are consistent with the acceptance guideline divisions suggested by the Standard Review Plan[(2)] (See Subsection 15.0.1.7). The subgroups are defined below:

C.1 Limiting Fault - 1

A Limiting Fault - 1 event has a low probability of occurring during the ~~assumed 40 year~~ lifetime for a particular plant.

C.2 Limiting Fault - 2

A Limiting Fault - 2 event has a very low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

C.3 Limiting Fault - 3

A Limiting Fault - 3 event has an exceedingly low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

15.0.1.4 Event Group Frequencies

The estimated frequency of occurrence of an Event Group is calculated from the sum of reported occurrences of the initiating events in that Event Group as observed in United States commercial PWR plants or from other non-nuclear related experience, i.e., high energy pipe break data. Conservative factors are applied to the estimated frequencies to determine a conservative upper bound frequency, referred to as the expected frequency of occurrence of an Event Group. (All initiating events in an Event Group are assumed to have the expected frequency of occurrence of the Event Group for the purpose of applying the acceptance guidelines.) The expected frequency serves as the basis for assigning each Event Group to one of the five frequency groups defined in Subsection 15.0.1.3. Table 15.0-2 shows all Event Groups positioned on the type/frequency matrix.

15.0.1.5 Event Combinations

Additional failures and/or special plant conditions are combined (via event tree analysis) with initiating events to generate event combinations. The frequency of and event combination is calculated by combining the expected frequency of an initiating event and the conditional probability of each additional failure or special plant condition. The resultant frequency serves as the basis for assigning event combinations to one of the five frequency groups defined in Subsection 15.0.1.3.

Additional failures are divided into the following four groups:

a) High-probability dependent occurrences

b) Low-probability dependent occurrences

c) High-probability independent occurrences

d) Low-probability independent occurrences

A dependent occurrence is an action which occurs as a direct result of an initiating event. All high probability dependent occurrences (e.g., turbine trip on reactor trip) are assigned a probability of one and are included in the definition of the initiating event.

An independent occurrence is a random, pre-existing failure, i.e., a failure which has occurred some time before an initiating event. The impact of this failure is not apparent until an initiating event causes the system containing the failure to perform an action which cannot be performed correctly.

15.2.5 LIMITING FAULT-3 EVENTS

15.2.5.1 Limiting Offsite Dose Event

None of the LF-3 event group and event group combinations resulting in a decreased heat removal by the secondary system shown in Table 15.2.5-1 release a significant amount of radioactivity to the atmosphere. The site boundary dose which would occur during the most adverse of these event groups or event combinations is well within the acceptance guideline specified in Table 15.0-4.

15.2.5.1.1 Feedwater Line Break Event (Reload Cycles)

Feedwater system pipe breaks are analyzed to confirm that the reactor primary system is maintained in a safe status for a range of feedwater line breaks up to and including a break equivalent in area to the double-ended rupture of the largest feedwater line. In the following discussion, feedwater line breaks will be categorized as small or large.

A large feedwater line break is any feedwater line break with an equivalent break area greater than 0.2 ft^2 (equivalent break size greater than a double-ended rupture for a 6 inch diameter pipe). Based on the nuclear industry piping experience information in WASH-1400 (Reference 4), the EPRI Utility Requirements Document (Reference 5), and the EPRI Piping Failure Study (Reference 6), the recurrence frequency for a large feedwater line break was estimated to be on the order of 1×10^{-4} per year. Therefore, a large feedwater line break with an equivalent break area greater than 0.2 ft^2 is an event with a very low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

The nuclear industry operating experience information in WASH-1400 (Reference 4), the EPRI Utility Requirements Docment (Reference 5), and the EPRI Piping Failure Study (Reference 6) was used to determine the recurrence frequency for any feedwater line break with a concurrent loss of offsite power on reactor trip. The probability of a loss of offsite power was estimated to be 1×10^{-3} and the recurrence frequency for feedwater line breaks of any size was estimated to be 6.2×10^{-3} per year. Based on this data, the frequency for any feedwater line break with a concurrent loss of offsite power on reactor trip is an event with an exceedingly low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

15.2.5.1.1.1 Small Feedwater Line Break Event (Reload Cycles)

15.2.5.1.1.1.1 Identification of Causes

The Small Feedwater Line Break Event was Analyzed to ensure that the site boundary doses would not exceed a small fraction of the 10CFR100 guidelines and that the peak RCS pressure would not exceed the upset pressure limit of 2750 psia.

A Feedwater Line Break Event is defined as the failure of a main feedwater system pipe during plant operation. A rupture in the main feedwater system rapidly reduces the steam generator secondary inventory causing a partial loss of the secondary heat sink, thereby allowing heat up of the Reactor Coolant System (RCS). The RCS is protected from over-pressurization by the high pressurizer pressure trip and the pressurizer safety valves.

15.2-146 Amendment No. ~~13, (05/00)~~ [LATER]

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CHAPTER 18.0
[NEW]

18.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES ACTIVITIES

The integrated plant assessment for license renewal identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This chapter describes these programs and their planned implementation.

This chapter also discusses the evaluation results for each of the plant-specific time-limited aging analyses performed for license renewal. The evaluations have demonstrated that: the analyses remain valid for the period of extended operation; the analyses have been projected to the end of the period of extended operation; or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

No 10 CFR 50.12 exemptions involving a time-limited aging analysis as defined in 10 CFR 54.3 were identified for St. Lucie Unit 2.

18.1 NEW PROGRAMS

18.1.1 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

The Galvanic Corrosion Susceptibility Inspection Program manages the aging effect of loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The program involves selected, one-time inspections on the surfaces of piping and components with the greatest susceptibility to galvanic corrosion. Baseline examinations in select systems will be performed and evaluated to establish if the corrosion mechanism is active. Based on the results of these inspections, the need for follow-up examinations or programmatic corrective actions will be established. This new program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

18.1.2 PIPE WALL THINNING INSPECTION PROGRAM

The Pipe Wall Thinning Inspection Program manages the aging effect of localized loss of material due to erosion of the internal surfaces of stainless steel Auxiliary Feedwater System piping downstream of the recirculation orifices, and carbon steel Component Cooling Water System piping associated with control room air conditioning. Examinations will be performed using volumetric techniques such as ultrasonic testing or radiography. The initial inspection will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

18.1.3 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

The Reactor Vessel Internals Inspection Program manages the aging effects of irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness, loss of mechanical closure integrity of bolted joints, and dimensional changes due to void swelling. The program consists of a one-time VT-1 visual examination and, in some cases, enhanced VT-1 examinations of selected reactor vessel internals parts to be performed during the second half of the period of extended operation. This inspection will be performed in addition to and in conjunction with the examinations required by the St. Lucie ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The examinations will be focused on areas of potential aging effects based on the highest projected combination of stress and fluence. For cast austenitic stainless steel (CASS) parts, analytical methods will be used to identify reactor vessel internals parts that are susceptible to loss of fracture toughness due to thermal embrittlement.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial 40-year operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria.

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 the NRC with a report describing this inspection plan prior to its implementation. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 2.

18.1.5 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

The St. Lucie Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (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. Aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2 EXISTING PROGRAMS

18.2.1 ALLOY 600 INSPECTION PROGRAM

This program manages the aging effect of cracking due to primary water stress corrosion (PWSCC) for susceptible Alloy 600 components within the Reactor Coolant System (RCS) pressure boundary. This includes the reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, control element drive mechanism motor housing lower end fittings, RCS piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings and RCS piping dissimilar metal welds. The program includes examinations of the reactor vessel head penetrations to detect crack initiation consistent with St. Lucie Plant's response to NRC Bulletin 2001-01 and on-going Nuclear Energy Institute (NEI) and Electric Power Research Institute (EPRI) Materials Reliability Project recommendations. Visual examination of external surfaces of susceptible locations during outages, which is included as part of the Boric Acid Wastage Surveillance Program, is also utilized to manage cracking.

18.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

18.2.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program inspections identify and correct degradation in Class 1, 2, and 3 components and piping. The program manages the aging effects of loss of material, cracking, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The program provides for inspection and examination of accessible components, including the reactor vessel, reactor vessel internals, steam generators, welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. This action will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.2.2 ASME SECTION XI, SUBSECTION IWE INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsection IWE Inservice Inspection Program inspections identify and correct degradation of pressure-retaining components and their integral attachments to the Class MC steel Containments. The program manages the aging effects of loss of material and loss of seal. The program provides for inspection and examination of Containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE.

18.2.2.3 ASME SECTION XI, SUBSECTION IWF INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsection IWF Inservice Inspection Program inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This program manages the aging effect of loss of material. The scope of the program provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

18.2.3 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

The Boric Acid Wastage Surveillance Program manages the aging effects of loss of material and loss of mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. The program addresses the RCS and structures and components containing, or exposed to, borated water. This program utilizes systematic inspections, leakage evaluations, and corrective actions to ensure that boric acid corrosion does not lead to degradation of the pressure boundary or the structural integrity of components, supports, or structures in proximity to borated water systems. This program includes commitments in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

Portions of the Waste Management System within the scope of license renewal are not currently included in the Boric Acid Wastage Surveillance Program. As such, the scope of the program will be enhanced to include these components and to provide for the inspection and evaluation of adjacent structures and components when leakage is identified. This action will be completed prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.4 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program manages the aging effects of loss of material, cracking, and fouling for primary and secondary systems, closed cooling water, and fuel oil systems, structures, and components. The aging effects are minimized or prevented by controlling the chemical species that cause the underlying mechanism(s) that results in these aging effects. Alternatively, chemical agents, such as corrosion inhibitors and biocides, are introduced to prevent certain aging effects. The program includes sampling activities and analysis. The program provides assurance that elevated levels of contaminants and oxygen do not exist in the systems, structures, and components covered by the program, and thus prevents and minimizes the occurrences of aging effects.

18.2.5 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is not credited as an aging management program; however, program evaluations of electrical equipment are identified as time-limited aging analyses.

Equipment covered by the Environmental Qualification Program has been evaluated to determine if the existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment initially qualified for 40 years or less. When analysis cannot justify a qualified life in excess of the license renewal period, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life in accordance with the Environmental Qualification Program.

18.2.6 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program is considered a confirmatory program to ensure that fatigue time-limited aging analysis assumptions remain valid for the period of extended operation; it is not credited as an aging management program.

The Fatigue Monitoring Program is designed to track design cycles to ensure that RCS components remain within their design fatigue limits. Design cycle limits for St. Lucie Unit 2 are provided in Sections 3.9.3.1 and 5.4.2.1. The specific fatigue analyses validated by the Fatigue Monitoring Program are associated with the reactor vessel, reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and Class 1 RCS piping. Administrative procedures provide the methodology for logging design cycles. These procedures will be enhanced to provide guidance in the event design cycle limits are approached. This action will be completed prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.7 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the aging effect of loss of material for the components of the Fire Protection System. Additionally, this program manages the aging effect of loss of material for structural components associated with fire protection. Appendix 9.5A contains a detailed discussion of the Fire Protection Program.

18.2.8 FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The Flow Accelerated Corrosion Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping associated with the Main Steam, Reactor Coolant (steam generators), Main Feedwater, and Steam Generator Blowdown Systems, and is based on industry guidelines and experience. The program includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and follow-up inspections.

The Flow Accelerated Corrosion Program will be enhanced to address internal and external loss of material of selected steam trap lines due to flow accelerated corrosion and external general corrosion. This action will be completed prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.9 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

The Intake Cooling Water System Inspection Program manages the aging effects of loss of material due to various corrosion mechanisms, and particulate and biological fouling for Intake Cooling Water (ICW) System components and the ICW side of the Component Cooling Water heat exchangers. The program includes inspections, performance testing, evaluations, and corrective actions that are performed as a result of FPL commitments in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

18.2.10 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of loss of material, cracking, loss of seal, and fouling (mechanical components only) for various plant systems, structures, and components. The scope of the program provides for visual examination of selected surfaces of specific systems, structures, and components. Additionally, the program provides for replacement/refurbishment of selected components on a specified frequency, as appropriate, and periodic sampling and water removal from hydraulic accumulators and fuel oil storage tanks. The frequency of inspections varies depending on the specific component, the aging effect being managed, and plant operating experience.

Specific enhancements to the scope of this program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.11 REACTOR VESSEL INTEGRITY PROGRAM

The Reactor Vessel Integrity Program manages reactor vessel irradiation embrittlement and encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Program documentation will be enhanced to integrate aspects of the Reactor Vessel Integrity Program prior to the end of the initial operating license term for St. Lucie Unit 2.

18.2.11.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

This subprogram manages the aging effect of reduction in fracture toughness of the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens. The Reactor Vessel Surveillance Capsule Removal and Evaluation subprogram is an NRC-approved program that meets the requirements of 10 CFR 50, Appendix H. The surveillance capsule withdrawal schedule is specified in Table 5.3-9.

18.2.11.2 FLUENCE AND UNCERTAINTY CALCULATIONS

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates welds.

18.2.11.3 MONITORING EFFECTIVE FULL POWER YEARS

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessel to ensure that the pressure-temperature limits and end-of-life reference temperatures are not exceeded.

18.2.11.4 PRESSURE-TEMPERATURE LIMIT CURVES

This subprogram provides pressure-temperature limit curves for the reactor vessel to establish the RCS operating limits. The pressure-temperature limit curves are included in the Technical Specifications.

18.2.12 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program is consistent with the guidelines provided by the Nuclear Energy Institute’s NEI 97-06, "Steam Generator Program Guidelines." The program ensures that steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The program manages the aging effects of cracking and loss of material.

18.2.13 SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, loss of seal, and change in material properties. The program provides for periodic visual inspection and examination for degradation of accessible surfaces of specific systems, structures, and components, and corrective actions, as required, based on these inspections.

This program will be enhanced to provide guidance for managing the aging effects of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. These enhancements will be made prior to the end of the initial operating license term for St. Lucie Unit 2.

18.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

18.3.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The St. Lucie Unit 2 reactor vessel is described in Chapters 4 and 5. Time-limited aging analyses (TLAAs) applicable to the reactor vessel are:

- pressurized thermal shock
- upper-shelf energy
- pressure-temperature limits

The Reactor Vessel Integrity Program, described in Subsection 18.2.11, manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, Charpy upper-shelf energy, and pressure-temperature limits to ensure continuing vessel integrity through the period of extended operation.

18.3.1.1 PRESSURIZED THERMAL SHOCK

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility.

The calculated RT_{PTS} values that bound the 60-year period of operation for the St. Lucie Unit 2 reactor vessel are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the reactor vessel during the license renewal period.

The analysis associated with pressurized thermal shock 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).

18.3.1.2 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G, requires licensees to submit an analysis at least 3 years prior to the time that the USE of any reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing.

An evaluation was performed to demonstrate continued acceptable margins of safety against fracture through the end of the period of extended operation. All reactor vessel beltline material USE projections remain acceptably above the 10 CFR 50, Appendix G, limit of 50 ft-lbs at the end of the 60-year period of operation using a conservative bounding fluence.

The analysis associated with USE 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).

18.3.1.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, stipulate that heatup and cooldown of the reactor pressure vessel be accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within the limits of Appendix G defined by the reactor vessel fluence.

The heatup and cooldown pressure-temperature limits are presented in the Unit 2 Technical Specifications. The pressure-temperature curves will be updated as the operating schedule requires. In addition, low temperature overpressure protection (LTOP) requirements will be updated to ensure that the pressure temperature limits are not exceeded for postulated plant transients.

The analyses associated with reactor vessel pressure-temperature limits for St. Lucie Unit 2 will be available prior to entering the period of extended operation, in accordance with the requirements of the Reactor Vessel Integrity Program and consistent with 10 CFR 54.21(c)(1)(ii).

18.3.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for St. Lucie Unit 2. Specific components have been designed considering design cycle assumptions, as listed in vendor specifications and in Section 3.9.3.

18.3.2.1 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 1 COMPONENTS

The reactor vessel (including control element drive mechanisms), reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and reactor coolant piping have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The pressurizer surge line was reanalyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." The design code requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded.

Fatigue usage factors for critical locations in the St. Lucie Unit 2 Nuclear Steam Supply System Class 1 components were determined using design cycles that were specified in the plant design process or as a result of industry fatigue issues (e.g., thermal stratification). These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for the Class 1 components satisfying ASME fatigue usage design requirements.

Experience has shown that actual plant operation is often very conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the period of extended operation, the design cycles applicable to the Class 1 components were assembled.

The actual frequency of occurrence for the fatigue sensitive design cycles was determined and compared to the design cycle set. The severity of the actual plant cycles was also compared to the severity of the design cycles. These comparisons were performed in order to demonstrate that on an event-by-event basis the design cycle profiles envelope actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the Fatigue Monitoring Program. The reviews described above concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the structural integrity of the Class 1 components have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program.

18.3.2.2 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 2 AND 3, AND ANSI B31.1 COMPONENTS

St. Lucie Unit 2 has a number of piping systems within the scope of license renewal that were designed to the requirements of ASME Section III, Class 2 and 3, or ANSI B31.1, "Power Piping." Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to operations. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years.

A review of ASME Section III, Class 2 and 3, and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperatures. Based on industry guidance, any piping system with operating temperatures less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Under current plant operating practices, piping systems within the scope of license renewal are only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady-state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or for periodic testing. The review of applicable plant systems determined that, except for the RCS hot-leg sample piping, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. Therefore, the current piping analyses remain valid for the period of extended operation.

The RCS hot-leg sample lines could exceed the 7000 equivalent full temperature thermal cycles during the period of extended operation based on the current sampling practices. The sample piping and tubing were re-evaluated to consider the projected number of cycles and the analyses were found acceptable for the period of extended operation.

Except for the RCS hot-leg sample lines, the ASME Section III, Class 2 and 3, and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The RCS hot-leg sample lines' fatigue analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.3.2.3 ENVIRONMENTALLY ASSISTED FATIGUE

Generic Safety Issue (GSI) 190 was initiated by the NRC staff because of concerns about the potential effects of reactor water environments on RCS component fatigue life during the period of extended operation. The FPL approach to address reactor water environmental effects accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 60-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment.

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995, fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system (NSSS) vendors. The pressurized water reactor (PWR) calculations included in NUREG/CR-6260, especially for the "Older Vintage Combustion Engineering Plant," match St. Lucie relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the St. Lucie Unit 2 design.

Environmental fatigue calculations have been performed for St. Lucie Unit 2 for those component locations included in NUREG/CR-6260 using the appropriate methods contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998, or NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999, as appropriate. Based on these results, all component locations were determined to be acceptable for the period of extended operation, with the exception of the pressurizer surge line (specifically the surge line elbow below the pressurizer).

FPL has selected aging management to address pressurizer surge line fatigue during the period of extended operation, in lieu of performing additional analyses to refine the fatigue usage factors. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the extended period of operation by the continued performance of the St. Lucie ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program, as described in Subsection 18.2.2.1. Additionally, specific requirements will be included to evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue (see Subsection 18.2.2.1).

18.3.3 ENVIRONMENTAL QUALIFICATION

The thermal, radiation, and wear cycle aging analyses of plant electrical/I&C components have been identified as TLAAs for St. Lucie Unit 2. In particular, the environmental qualification evaluations of electrical equipment with a 40-year qualified life or greater have been determined to be TLAAs.

Equipment included in the St. Lucie Environmental Qualification Program has been evaluated to determine if existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment currently qualified at St. Lucie for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding their qualified lives in accordance with the Environmental Qualification Program, as described in Subsection 18.2.5.

Age-related service conditions that are applicable to the environmentally qualified equipment (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current environmental qualification analyses are bounding. The evaluations considered radiation, thermal, and wear cycle aging effects.

Therefore, the analyses associated with the environmental qualification of electrical equipment remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

18.3.4 CONTAINMENT PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I — Those which must accommodate considerable thermal movements (hot penetrations)
- Type II — Those which are not required to accommodate thermal movements (cold penetrations)
- Type III — Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV — Containment sump recirculation suction lines
- Type V — Fuel transfer tube

The containment penetration bellows fatigue analyses have been evaluated and determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.3.5 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed Nuclear Steam Supply Systems (NSSS), which included St. Lucie Unit 2. The LBB analysis was performed to show that any potential leaks that develop in the RCS primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the RCS loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which covers the extended period of operation. Therefore, the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA and no additional evaluation is required for the period of extended operation.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles are is consistent with those utilized in the fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The RCS primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

18.3.6 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs:

- Reactor Building Polar Crane
- Refueling Machine and Hoist
- Reactor Containment Building Auxiliary Telescoping Jib Crane
- Fuel Transfer Machine
- Spent Fuel Handling Machine
- Refueling Canal Bulkhead Monorail
- Cask Storage Pool Bulkhead Monorail
- Intake Structure Bridge Crane

(Note: The Fuel Cask Crane does not require a TLAA evaluation because the crane's lifting function is not in the scope of license renewal.)

The load cycles for these cranes were evaluated for the period of extended operation. For each crane, the actual usage over the projected life through the period of extended operation will be far less than the analyzed quantity of cycles. All the cranes in the scope of license renewal will continue to perform their intended function throughout the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, are valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

18.3.7 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

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 primary water stress corrosion cracking. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

A fracture mechanics analysis was performed and 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" weld based on a conservative postulated flaw size and flaw growth considering the applicable design cycles. The analysis concluded that the postulated flaw size in the instrument nozzle was acceptable for the remaining design life of the plant (30 years, or 75% of the original 40-year plant design life). Consequently, only 75% of the original design cycles was assumed in the flaw growth analysis. However, this analysis has been superseded by a subsequent analysis that considered 100% of the original design cycles, as discussed below.

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" weld were bounded by the fracture mechanics analysis provided in Combustion Engineering Owner's Group (CEOG) Topical Report CE NPSD-1198-P. FPL also documented in that response that the CEOG topical report is applicable to the Unit 2 pressurizer steam space nozzle repairs performed in 1994.

CEOG Topical Report CE NPSD-1198-P was submitted to the NRC February 15, 2001 to obtain generic approval of the Alloy 600/690 nozzle repair/replacement programs. The CEOG report provides a bounding flaw evaluation that covers all small diameter Alloy 600/690 nozzle repairs in accordance with ASME Section XI requirements. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 2 UFSAR. This generic analysis bounds the Class 1 fatigue design requirements of St. Lucie Unit 2. As discussed in Subsection 18.3.2.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The flaw growth analysis of the Unit 2 pressurizer steam space Alloy 600 instrument nozzle repairs has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

APPENDIX B

AGING MANAGEMENT PROGRAMS

TABLE OF CONTENTS

1.0 INTRODUCTION

The St. Lucie Units 1 and 2 Integrated Plant Assessment comprises four major activities, consistent with the NRC, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" [Reference B-1]. The first two activities, "Identification of Structures and Components that are Subject to Aging Management Review" and "Identification of Aging Effects Requiring Management," have been described in the body of this application. The remaining major activities, "Identification of Plant-Specific Programs That Will Manage the Identified Aging Effects Requiring Management" and "Aging Management Demonstration for Existing Programs," are described herein.

The St. Lucie programs described herein, with the exception of the Environmental Qualification Program and the Fatigue Monitoring Program, are credited for managing the effects of aging. The Environmental Qualification Program is credited for ensuring the qualified life of electrical and I&C components within the scope of 10 CFR 50.49 is maintained. The Fatigue Monitoring Program is credited for confirming that Reactor Coolant System design cycle assumptions remain valid. The programs described include both existing programs and new programs currently not being conducted.

Section 3.0 of this Appendix contains a description of each program that includes a statement that the program is either consistent with the GALL Report [Reference B-2], consistent with the GALL Report with exceptions, or it is a plant-specific program. Aging management programs provide reasonable assurance that the effects of aging will be adequately managed so that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation. The demonstrations, along with the program and activity descriptions, meet the requirements of 10 CFR 54.21(a)(3). Along with the technical information contained in the body of this application, this appendix is intended to allow the NRC to make the finding contained in 10 CFR 54.29(a)(1).

Commitment dates associated with the implementation of new programs and enhancements to existing programs are contained in Appendix A.

2.0 AGING MANAGEMENT PROGRAM ATTRIBUTES

The attributes that are used to describe aging management programs are discussed in this section. NEI 95-10 [Reference B-3], Sections 4.2 and 4.3, served as the primary input to the attribute definitions.

The St. Lucie aging management programs were compared to the aging management programs described in the GALL Report [Reference B-2]. For each program in Section 3.0 that has no corresponding GALL program, the attributes defined below are discussed and the program is identified as plant specific. For each program in Section 3.0 that was determined to be consistent with a GALL program, the GALL program reference is provided, and the only attribute discussed is "Operating Experience and Demonstration." For programs that are consistent with GALL, but for which clarification is required, the GALL program reference is provided and the clarifications are discussed in addition to the attribute "Operating Experience and Demonstration." Section 3.0 provides a listing of St. Lucie programs and identifies which ones are plant specific and which ones are consistent with GALL. The attribute information provided in Section 3.0 for plant-specific and GALL programs is consistent with the information provided to the NRC for the NEI License Renewal Demonstration Project [Reference B-4].

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. The FPL Quality Assurance Program meets the requirements provided by the NRC Regulatory Guidance and Industry Standards as listed in Appendix C of the FPL Topical Quality Assurance Report. 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.

The descriptions of the attributes for Corrective Actions and Administrative Controls are the same for all aging management programs credited for license renewal. Accordingly, discussions of Corrective Actions and Administrative Controls are not included in the summary descriptions of the individual programs in this appendix, but are presented below.

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.

Administrative Controls

This attribute is an identification of the plant administrative structure under which the programs are executed.

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 shall 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.

The remaining attribute definitions used to describe new and existing programs are:

Scope

This attribute is a clear statement of the reason why the program exists for license renewal.

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.

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.

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.

Monitoring and Trending

This attribute is a description of the monitoring, inspection, or testing frequency, and sample size (if applicable).

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.

Confirmation Process

This attribute is a description of the process to ensure that adequate corrective actions have been completed and are effective.

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. Program demonstration is also included in this summary.

3.0 AGING MANAGEMENT PROGRAMS

The following programs are credited to manage the aging effects (except as noted in Section 1.0) for license renewal.

New Aging Management Programs

- Condensate Storage Tank Cross-connect Buried Piping Inspection (plant-specific program; Unit 1 only)
- Galvanic Corrosion Susceptibility Inspection Program (plant-specific program)
- Pipe Wall Thinning Inspection Program (plant-specific program)
- Reactor Vessel Internals Inspection Program (plant-specific program)
- Small Bore Class 1 Piping Inspection (plant-specific program)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (GALL program)

Existing Aging Management Programs

- Alloy 600 Inspection Program (plant-specific program)
- ASME Section XI Inservice Inspection Program
    - ➢ ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (GALL program)
    - ➢ ASME Section XI, Subsection IWE Inservice Inspection Program (GALL program)
    - ➢ ASME Section XI, Subsection IWF Inservice Inspection Program (GALL program)
- Boraflex Surveillance Program (GALL program; Unit 1 only)
- Boric Acid Wastage Surveillance Program (GALL program)
- Chemistry Control Program
    - ➢ Chemistry Control Program - Water Chemistry Control Subprogram (GALL program)
    - ➢ Chemistry Control Program - Closed-Cycle Cooling Water System Subprogram (GALL program)
    - ➢ Chemistry Control Program - Fuel Oil Chemistry Subprogram (plant-specific program)
- Environmental Qualification Program (GALL program)
- Fatigue Monitoring Program (plant-specific program)
- Fire Protection Program (plant-specific program)
- Flow Accelerated Corrosion Program (GALL program)
- Intake Cooling Water System Inspection Program (plant-specific program)
- Periodic Surveillance and Preventive Maintenance Program (plant-specific program)

- Reactor Vessel Integrity Program (plant-specific program)
- Steam Generator Integrity Program (GALL program)
- Systems and Structures Monitoring Program (plant-specific program)

Demonstration that each of the above programs adequately addresses the identified aging effect is in the following sections.

3.1 NEW AGING MANAGEMENT PROGRAMS

3.1.1 CONDENSATE STORAGE TANK CROSS-CONNECT BURIED PIPING INSPECTION (Unit 1 only)

As identified in Chapter 3, the Condensate Storage Tank Cross-connect Buried Pipe Inspection is credited for aging management of Auxiliary Feedwater and Condensate piping.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program XI.M28, "Buried Piping and Tanks Surveillance," which is intended for carbon steel piping. The program cannot be applied to the condensate storage tank cross-connect because the pipe is stainless steel. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Scope

The inspection provides for visual examination to detect loss of material. The scope of the inspections involves the external surfaces of buried condensate storage tank cross-connect pipe. This inspection is credited for managing the external loss of material due to pitting and microbiologically influenced corrosion.

Preventive Actions

There are no preventive actions applicable to this inspection.

Parameters Monitored or Inspected

The inspection will assess the extent of external corrosion of the condensate storage tank 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 microbiologically influenced corrosion.

Detection of Aging Effects

The aging effect of loss of material will be evident from visual inspection.

Monitoring and Trending

The one-time inspection will provide confirmatory information on the condition of the pipe. 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.

Acceptance Criteria

The results of the examinations will be evaluated in accordance with the minimum wall thickness requirements of the applicable design code (ANSI B31.1).

Confirmation Process

Follow-up inspections, if required, will be scheduled based upon actual corrosion rates or inspection findings, and documented in accordance with the corrective action program.

Operating Experience and Demonstration

Visual inspection techniques have been used at St. Lucie Units 1 and 2 for many years. These techniques have proven successful at determining the extent of loss of material based on the surface conditions of piping/fittings and other components.

The Condensate Storage Tank Cross-connect Buried Piping Inspection is a new inspection that 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.

Based upon the above, the implementation of the Condensate Storage Tank Cross-connect Buried Piping Inspection will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.2 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

As identified in Chapter 3, the Galvanic Corrosion Susceptibility Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Auxiliary Feedwater and Condensate	Instrument Air
Component Cooling Water	Main Feedwater and Steam Generator Blowdown
Containment Cooling	Main Steam, Auxiliary Steam, and Turbine
Containment Spray	Primary Makeup Water
Diesel Generator and Support Systems	Safety Injection
Fire Protection	Turbine Cooling Water (Unit 1 only)
Fuel Pool Cooling	Ventilation

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Scope

This 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, baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The program involves one-time inspections whose results will be utilized to determine the need for additional programmatic actions.

Preventive Actions

Galvanic corrosion is caused by the presence of dissimilar metals in a conducting medium. Some components and systems utilize insulating flanges or cathodic protection as preventive measures to minimize galvanic interaction. The use of insulating flanges and cathodic protection performs a preventive function, but is not credited for elimination of galvanic corrosion.

Parameters Monitored or Inspected

The program will assess the loss of material due to galvanic corrosion between dissimilar metals in locations determined to have the greatest susceptibility for this aging mechanism. The most limiting locations will be selected based on high galvanic potential, high cathode/anode area ratio, and high conductivity of the fluid in contact with the metals.

Detection of Aging Effects

Visual inspections or volumetric examinations by qualified personnel will be utilized to address the extent of material loss. The aging effect, loss of material due to galvanic corrosion, will be evident by material loss at the location of the junction between the dissimilar metals.

Monitoring and Trending

Inspections will be conducted on a sampling basis. Locations selected for inspection will represent those with the greatest susceptibility for galvanic corrosion. Initial inspection results will be utilized to assess the need for expanded sample locations.

The program will utilize visual inspections or volumetric examinations to address the extent of the material loss. Plant experience with galvanic corrosion has been limited and typically has occurred in systems exposed to salt water. Examinations and inspections will be performed using approved procedures.

Inspection frequency will be determined based on the corrosion rate identified during the initial inspections. Instructions will be developed to assist in the determination of frequency and scope of future inspections.

Acceptance Criteria

The program consists of a confirmatory one-time inspection of piping to verify that loss of material due to galvanic corrosion is not occurring. In the event that significant loss of material is detected during the inspection, appropriate corrective actions will be established in accordance with the corrective action program. Evaluation of the inspection results will consider the minimum required wall thickness for the component consistent with the applicable design codes.

Confirmation Process

Follow-up inspections, if required, will be scheduled based upon inspection findings and documented in accordance with the corrective action program.

Operating Experience and Demonstration

The 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. This examination 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, because locations selected for inspection will represent those with the greatest susceptibility for galvanic corrosion. Initial inspection results will be utilized to assess the need for expanded sample locations.

There have been instances of galvanic corrosion at St. Lucie, primarily in the Intake Cooling Water System. Galvanic corrosion, for the Intake Cooling Water System, is managed using the Intake Cooling Water Inspection Program and 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.

Based upon the above, the implementation of the Galvanic Corrosion Susceptibility Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.3 PIPE WALL THINNING INSPECTION PROGRAM

As identified in Chapter 3, the Pipe Wall Thinning Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Auxiliary Feedwater and Condensate

Component Cooling Water (Unit 2 only)

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Scope

The program provides for volumetric examination methods to detect loss of material by measuring wall thickness. The scope of the inspections involves examination of the Units 1 and 2 Auxiliary Feedwater stainless steel piping downstream of the recirculation orifices. The scope of this program also includes Unit 2 carbon steel control room air conditioning Component Cooling Water return piping. This inspection is credited for managing the internal loss of material due to erosion.

Preventive Actions

No preventive actions are applicable to this inspection.

Parameters Monitored or Inspected

The program will assess the extent of localized erosion of the internal surfaces of the Units 1 and 2 Auxiliary Feedwater stainless steel piping downstream of the recirculation orifices by measuring pipe wall thickness. The program also includes the Unit 2 carbon steel control room air conditioning Component Cooling Water return piping. This inspection is credited for managing the internal loss of material due to erosion.

Detection of Aging Effects

The detection of loss of material will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing or radiography.

Monitoring and Trending

This program involves periodic volumetric inspections. The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, corrosion rates, and minimum required wall thickness. The need for any replacements or change in examination frequency will be determined based on the results of each inspection, to ensure that the minimum wall thickness of the piping is maintained.

Acceptance Criteria

The program consists of periodic inspections of piping to verify the extent of loss of material due to erosion. Evaluation of the inspection results will consider the minimum required wall thickness in accordance with ANSI B31.7 for Unit 1 Auxiliary Feedwater piping, and ASME Section III for Unit 2 Auxiliary Feedwater and Component Cooling Water piping.

Confirmation Process

Follow-up inspections, if required, will be scheduled based upon inspection findings and documented in accordance with the corrective action program.

Operating Experience and Demonstration

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, St. Lucie elected to periodically inspect the susceptible lines to manage loss of material. Volumetric inspection techniques have been used to in monitoring 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 piping condition in many other plant systems.

Based upon the above, the implementation of the Pipe Wall Thinning Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.4 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

As identified in Chapter 3, the Reactor Vessel Internals Inspection Program is credited for aging management of the reactor vessel internals in the Reactor Coolant Systems.

This program is plant-specific. Although there are two reactor vessel internals aging management programs described in the GALL Report [Reference B-2], the St. Lucie program is integrated and cannot be compared directly.

The Reactor Vessel Internals Inspection Program will involve the combination of several activities culminating in the inspection of the St. Lucie Units 1 and 2 reactor vessel internals, once for each Unit, during the 20-year period of extended operation. The program is intended to supplement the reactor vessel internals inspections required by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Ongoing industry efforts are aimed at characterizing the aging effects associated with the reactor vessel internals. Further understanding of these aging effects will be developed by the industry over time and will provide additional bases for the inspections under this program. Pending results of industry progress with regard to validation of the significance of dimensional changes due to void swelling, the visual examinations described below may be supplemented to incorporate requirements for dimensional verification of critical reactor vessel internals parts.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Scope

This program manages the aging effects of cracking due to irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness due to irradiation and thermal embrittlement, and loss of mechanical closure integrity of bolted joints on accessible parts of the St. Lucie Units 1 and 2 reactor vessel internals. This program consists of VT-1, and in some cases enhanced VT-1, examinations that typically include remote visual inspections utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Other demonstrated acceptable inspection methods will be utilized for bolted joints, if deemed necessary.

The program also provides screening criteria to determine the susceptibility of cast austenitic stainless steel (CASS) parts to thermal embrittlement based on the casting method, molybdenum content, and percent ferrite.

Preventive Actions

There are no practical preventive actions available that will prevent IASCC, reduction in fracture toughness due to irradiation and thermal embrittlement, and loss of mechanical closure integrity of the reactor vessel internals bolted joints. However, to minimize the potential for stress corrosion cracking, the concentrations of chlorides, fluorides, and sulfates in the reactor coolant fluid are controlled by implementation of the Chemistry Control Program.

Parameters Monitored or Inspected

This examination monitors cracking and reduction in fracture toughness on the reactor vessel internals accessible parts, and loss of mechanical closure integrity of reactor vessel internals bolted joints.

Detection of Aging Effects

The aging effects of IASCC and reduction in fracture toughness due to irradiation and thermal embrittlement on selected reactor vessel internals parts will be detected by the performance of VT-1 examinations for the detection of cracks. Cracking is expected to initiate at the surface and will be detectable by the VT-1 visual examination.

Additionally, certain reactor vessel internals parts will be selected as leading locations for IASCC based on the highest projected combination of fluence and stress. For these 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 reactor vessel internals parts potentially susceptible to IASCC will be inspected utilizing this enhanced VT-1 examination.

Monitoring and Trending

The VT-1, and in some cases enhanced VT-1, examinations of selected reactor vessel internals 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 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program reactor vessel internals inspections. In order to develop a baseline for the extended period, FPL plans to perform the first of these reactor vessel internals inspections early in the renewal period on 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 Unit 2 inspection will be conducted early in the second 10-year inspection interval in its license renewal term.

Acceptance Criteria

Acceptance criteria will be developed prior to the visual examination. Cracks will be evaluated for determination of the need and method of repair or replacement.

Confirmation Process

Any follow-up examination will be based on the evaluation of the initial examination results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

The VT-1, and in some cases enhanced VT-1, examinations to be performed by this program are an inspection with demonstrated capability and a proven industry record to detect potential cracking. These examinations are performed utilizing approved plant procedures and qualified personnel. The remote visual examination proposed by this program utilizing equipment, such as television cameras, fiberoptic scopes, periscopes, etc., has been demonstrated previously as an effective method to detect cracking of reactor vessel internals parts. Similar visual examinations were successfully performed at St. Lucie Unit 1 during the core support barrel repair.

FPL participates in both the Westinghouse Owners Group (WOG) and the Combustion Engineering Owners Group (CEOG). There have been active programs in the WOG, particularly in the area of baffle/former bolting, and FPL has participated in these programs from the inception, including the Joint Owners Baffle Bolt (JOBB) program. Most of the current industry activities addressing aging effects on reactor vessel internals are being conducted under the EPRI Materials Reliability Project (MRP).

FPL has access to MRP products related to the reactor vessel as they are completed. The MRP strategy is to evaluate potential aging mechanisms and their effects on specific reactor vessel internals parts by evaluating causal parameters such as fluence, material properties, state of stress, etc. Critical locations can thereby be identified and tailored inspections can be conducted on either an integrated industry, NSSS, or plant-specific basis.

The following MRP projects are underway:

- Material testing of baffle/former bolts removed from the Point Beach, Farley, and Ginna nuclear power plants and determination of bolt operating parameters.
- Evaluation of the effects of irradiation, which include IASCC, swelling, and stress relaxation in PWRs.
- Evaluation of irradiated material properties.
- Void swelling "white paper" including available data and effects on reactor vessel internals.
- Development of a long-term reactor vessel internals aging management strategy.

Various tasks are addressed as JOBB program activities, which include a body of work to be performed by Electricite'de France. As these projects are completed, FPL will evaluate the results and factor them into the Reactor Vessel Internals Inspection Program, as applicable.

Based upon the above, implementation of the Reactor Vessel Internals Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.5 SMALL BORE CLASS 1 PIPING INSPECTION

As identified in Chapter 3, the Small Bore Class 1 Piping Inspection is credited for aging management of small bore Class 1 piping in the Reactor Coolant Systems.

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, susceptibility to any age-related cracking mechanisms.

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. FPL will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to the implementation of this inspection. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Scope

The Small Bore Class 1 Piping Inspection will be a one-time volumetric examination of a sample of Class 1 piping less than 4 inches in diameter.

Preventive Actions

No preventive actions are applicable to this inspection.

Parameters Monitored or Inspected

The volumetric technique chosen will permit detection and sizing of cracking of small bore Class 1 piping.

Detection of Aging Effects

The detection of cracking will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing or radiography.

Monitoring and Trending

As noted above, this is a one-time inspection and, as such, no monitoring and trending are anticipated. 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 sample of welds to be examined will be selected by using a risk informed approach. The risk informed approach consists of two essential elements: (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.

Acceptance Criteria

Any cracks identified will be evaluated and if appropriate, entered into the corrective action program.

Confirmation Process

Any follow-up inspection required will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

This one-time inspection is a new activity that will use techniques with demonstrated capability and a proven industry record to detect piping weld and base material flaws. Approved and qualified volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel.

The Small Bore Class 1 Piping Inspection Program will incorporate results and recommendations from industry initiatives. For example, the current EPRI initiative to assemble guidance on non-destructive examination methodologies, and to provide recommendations and variables for specific non-destructive examination techniques will be incorporated in the St. Lucie Nuclear Plant program.

Based upon the above, the implementation of the Small Bore Class 1 Piping Inspection will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.1.6 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL PROGRAM

As identified in Chapter 3, the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is credited for aging management of CASS Reactor Coolant System components.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is consistent with the ten attributes of Aging Management Program XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," specified in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Operating Experience and Demonstration

The proposed Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program monitors the effects of reduction in fracture toughness on the intended function of the specific component by identifying the CASS materials that are susceptible to thermal aging embrittlement. For potentially susceptible materials, the program recommends either an enhanced volumetric examination to detect and size cracks, or a plant- or component-specific flaw tolerance evaluation. The proposed aging management program was developed using research data obtained on both laboratory-aged and service-aged materials.

Based upon the above, the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2 EXISTING AGING MANAGEMENT PROGRAMS

3.2.1 ALLOY 600 INSPECTION PROGRAM

As identified in Chapter 3, the Alloy 600 Inspection Program is credited for aging management of the Reactor Coolant System.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program X.M11, "Nickel-Alloy Nozzles and Penetrations," which applies primarily to the reactor vessel head penetrations. The St. Lucie program scope includes all Alloy 600 Reactor Coolant System pressure boundary components susceptible to PWSCC, some of which are not addressed in the GALL program. Also, the GALL program includes monitoring and examination activities that are included in separate programs at St. Lucie, i.e., Chemistry Control Program, Boric Acid Wastage Surveillance Program, and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Note that the Alloy 600 Inspection Program described below incorporates FPL's responses to NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Head Penetrations," and NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles."

As corrective actions to address PWSCC of Alloy 600 material, selected instrument nozzles have been replaced with Alloy 690 material which is not susceptible to PWSCC.

Scope

The Alloy 600 Inspection Program encompasses the St. Lucie Units 1 and 2 Alloy 600 Reactor Coolant System pressure boundary components including reactor vessel head 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. This program manages the aging effect of cracking due to PWSCC by utilizing the walkdown inspections, performed during every refueling outage, for visual inspection of the reactor vessel head external surfaces and all other susceptible leakage locations in the Reactor Coolant System as required by the Boric Acid Wastage Surveillance Program. The program also includes those reactor vessel head inspections to be performed in accordance with the St. Lucie commitments to NRC Generic Letter 97-01 and NRC Bulletin 2001-01 [References B-5 and B-6]. The scope and schedule of future reactor vessel head penetration inspection requirements is pending the issuance of industry guidance.

Preventive Actions

The program includes several PWSCC mitigation or preventive actions including:

- Nickel plating - this technique provides a barrier to the primary water and has been implemented on the Unit 1 pressurizer heater sleeves.
- Replacement of leaking Alloy 600 instrument nozzles with Alloy 690 material, which is not susceptible to PWSCC.

- Preventive replacement of selected pressurizer and Reactor Coolant System piping instrument nozzles with Alloy 690 material, which is not susceptible to PWSCC.

Parameters Monitored or Inspected

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.

Detection of Aging Effects

A visual inspection of 100% of the Unit 1 and 2 reactor vessel heads, in accordance with the St. Lucie commitments to NRC Bulletin 2001-01, will be performed. The results of the inspection will be utilized to determine the need for additional bare metal visual or volumetric examinations.

Leak tests and walkdowns are used for detecting PWSCC of Alloy 600 components. The leak tests consist of visual inspections of each susceptible location in accordance with requirements of the existing Boric Acid Wastage Surveillance Program. Leakage is detected by steam discharge, borated water, or other evidence of fluid escape.

Monitoring and Trending

In response to NRC Bulletin 2001-01, the industry will develop a follow-up examination plan for reactor vessel head penetrations. The schedule and frequency for follow-up examinations will be determined based on the results of the initial examinations and pending industry guidance to be provided by the EPRI MRP and NEI. The visual inspections of the reactor vessel head area and other Reactor Coolant System Alloy 600 components are performed in accordance with the Boric Acid Wastage Surveillance Program.

Acceptance Criteria

The acceptance criteria for identified flaws will be developed using approved fracture mechanics methods, and industry- or plant-specific data. Evaluations would consider the stresses at the flaw location and industry developed crack propagation rates, if the flaw is to be left in service, prior to implementing any corrective action. The acceptance criterion for the visual inspections is no pressure boundary leakage.

Confirmation Process

For the Reactor Coolant System Alloy 600 pressure boundary components, confirmation will include inspection of the repaired/replaced component and pressure boundary integrity verification in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Additional testing/examinations will be performed, if required, by the corrective action program.

Operating Experience and Demonstration

St. Lucie has been an active participant in the CEOG, EPRI, and NEI initiatives regarding cracking of Alloy 600 Reactor Coolant System components. The Alloy 600 Inspection Program was created in response to NRC Generic Letter 97-01, and updated in response to NRC Bulletin 2001-01. This program has proven experience in addressing the concerns and requirements of the Generic Letter and the Bulletin. To date, St. Lucie has performed visual inspections on the top of the Units 1 and 2 reactor vessel heads for leakage as part of the Boric Acid Wastage Surveillance Program. No evidence of leakage from the Alloy 600 reactor vessel head penetrations has been identified.

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 visual inspections provided timely detection and repair of Reactor Coolant System pressure boundary leakage.

The St. Lucie Alloy 600 Inspection Program is based on the industry and St. Lucie responses to NRC Generic Letter 97-01 and NRC Bulletin 2001-01. This program utilizes analytical methods for prediction of cracking/propagation due to PWSCC and is validated by reactor vessel head penetration inspections performed by participating utilities.

Based upon the above, the implementation of the Alloy 600 Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

3.2.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Reactor Coolant

Containment Spray

The currently applicable ASME code years for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program are identified in FPL Letter L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7] and FPL Letter L-93-191, dated August 4, 1993, for Unit 2 [Reference B-8]. The program is consistent with the ten attributes of Aging Management Program XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC and IWD," specified in the GALL Report [Reference B-2], with the following clarification. This program credits ASME Code Case N-509 [Reference B-9], which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie. Although ASME Section XI, Subsection IWD is included in the scope of this program, this application does not credit Subsection IWD for managing the effects of aging. In addition, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. Commitment dates associated with the enhancements to this program are contained in Appendix A.

Operating Experience and Demonstration

ASME Section XI provides the rules and requirements for inservice inspection, testing, repair, and replacement of Class 1, 2, and 3 components. It has been shown to be generally effective in managing the aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. Components are chosen for inspection in accordance with the requirements of Subsections IWB, IWC, and IWD, and are inspected using volumetric, surface, or visual examination methods.

The inservice inspection of Class 1, 2, and 3 components and piping has been conducted since initial plant startup as required by Technical Specifications and 10 CFR 50.55a. These inspections have been documented and evaluated, and degraded conditions have been corrected.

Implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program at St. Lucie currently includes examinations of Class 1, 2 and 3 components over a ten-year interval. For Class 1 piping, the examinations have yielded only indications of surface anomalies and surface geometry with no indication of cracking. For Class 2 piping, FPL is monitoring a flaw on a Unit 2 Safety Injection line consistent with applicable code requirements.

Based upon the above, the implementation of the enhanced ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.2.2 ASME SECTION XI, SUBSECTION IWE INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsection IWE Inservice Inspection Program is credited for aging management of specific structural component/commodity groups in the Containments.

The ASME Section XI, Subsection IWE Inservice Inspection Program is consistent with the ten attributes of Aging Management Programs XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," specified in the GALL Report [Reference B-2]. For St. Lucie Units 1 and 2, leak rate testing in accordance with 10 CFR 50, Appendix J, is included as Category E-P in the ASME Section XI, Subsection IWE Inservice Inspection Program. The currently applicable ASME code years for the ASME Section XI, Subsection IWE Inservice Inspection Program are identified in FPL Letters L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7], and L-2000-227, dated November 13, 2000, for Unit 2 [Reference B-10].

Operating Experience and Demonstration

As stated in Subsection 3.5.1.1.1, the codes and standards used for the design and fabrication of the St. Lucie Containments are identified in Unit 1 UFSAR Section 3.8 and Unit 2 UFSAR Section 3.8. ASME Section XI, Subsection IWE was incorporated by reference into 10 CFR 50.55a, and accordingly, St. Lucie ASME Section XI, Subsection IWE Inservice Inspection Program was developed and implemented.

Containment leak-tight verification and visual examination of the steel components that are part of the leak-tight barrier have been conducted at St. Lucie since initial startup. Prior to the development of the ASME Section XI, Subsection IWE Inservice Inspection Program, visual examinations were performed in accordance with 10 CFR 50, Appendix J. Although the visual inspection is general in nature, it is intended to detect areas of widespread flaking, rust, pitting, gouges, and cracks or other visible indications on welds or structural elements. Detailed inspections and evaluations are performed as warranted if gross discrepancies are detected. Conditions noted during the inspection of the Containment are documented on inspection reports. An evaluation of inaccessible areas is performed when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

A review of the plant-specific operating experience determined that there were no significant degradations associated with the Containment vessels. The operating history identified included the following:

- 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 mis-alignment, 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 continued implementation of the ASME Section XI, Subsection IWE Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.2.3 ASME SECTION XI, SUBSECTION IWF INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsection IWF Inservice Inspection Program is credited for aging management of Class 1, 2, and 3 component supports in the following structures:

Component Cooling Water Areas	Intake Structures
Condensate Storage Tank Enclosures	Reactor Auxiliary Buildings
Containments	Steam Trestle Areas
Diesel Oil Equipment Enclosures	Ultimate Heat Sink Dam
Emergency Diesel Generator Buildings	Yard Structures
Fuel Handling Buildings	

The ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with the ten attributes of Aging Management Program XI.S3, "ASME Section XI, Subsection IWF," specified in the GALL Report [Reference B-2]. The currently applicable ASME code years for the ASME Section XI, Subsection IWF Inservice Inspection Program are identified in FPL Letter L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7], and FPL Letter L-93-191, dated August 4, 1993, for Unit 2 [Reference B-8].

Operating Experience and Demonstration

St. Lucie Technical Specifications and 10 CFR 50.55a require a program for the inspection of Class 1, 2, and 3 components (including supports). ASME Section XI provides the rules and requirements for inservice inspection, testing, repair, and replacement of Class 1, 2, and 3 component supports. The ASME Section XI, Subsection IWF Inservice Inspection Program applies to Class 1, 2, and 3 component supports (piping supports and supports other than piping supports).

The inservice inspection of the Class 1, 2, and 3 component supports has been conducted on both Units since plant initial start-up. 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 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.

Based upon the above, the continued implementation of the ASME Section XI, Subsection IWF Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.3 BORAFLEX SURVEILLANCE PROGRAM (Unit 1 only)

As identified in Chapter 3, the Boraflex Surveillance Program is credited for aging management of the spent fuel storage racks in the Unit 1 Fuel Handling Building.

The Boraflex Surveillance Program is consistent with the ten attributes of Aging Management Program XI.M22, "Boraflex Monitoring," specified in the GALL Report [Reference B-2]. Note that the GALL program discusses the aging effect of loss of boron carbide, whereas the St. Lucie program discusses the equivalent aging effect change in material properties for the neutron absorbing material. 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.

Operating Experience and Demonstration

St. Lucie Unit 1 initiated a blackness testing program following installation of high density spent fuel storage racks. The blackness testing has provided sufficient reliable data on the presence of Boraflex for use in criticality calculations to maintain the required 5% subcriticality margin for the five-year period of each test. The FPL response to NRC Generic Letter 96-04 [Reference B-11] assessed the capability of the Boraflex to maintain a 5% subcriticality margin and provided remedies for long-term Boraflex degradation.

The Boraflex Surveillance Program will be enhanced to include areal density testing. Areal density testing can provide a more accurate measurement of the degree of degradation of the Boraflex. Areal density testing has also been used successfully at various other nuclear power facilities, including FPL's Turkey Point Unit 3.

Based upon the above, the implementation of the enhanced Boraflex Surveillance Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Unit 1 CLB for the period of extended operation.

3.2.4 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

As identified in Chapter 3, the Boric Acid Wastage Surveillance Program is credited for aging management of specific cast iron, carbon steel, and low alloy steel component/ commodity groups, including adjacent structures, systems, and components, in the following systems and structures:

<u>Systems</u>

Chemical and Volume Control	Main Feedwater and Steam Generator Blowdown
Component Cooling Water	Main Steam, Auxiliary Steam, and Turbine
Containment Cooling	Miscellaneous Bulk Gas Supply
Containment Isolation	Primary Makeup Water
Containment Post Accident Monitoring	Reactor Coolant
Containment Spray	Safety Injection
Fire Protection	Sampling
Fuel Pool Cooling	Service Water
Instrument Air	Ventilation
Intake Cooling Water	Waste Management

<u>Structures</u>

Containments	Fuel Handling Buildings
Reactor Auxiliary Buildings	Yard Structures

The Boric Acid Wastage Surveillance Program is consistent with the ten attributes of Aging Management Program XI.M10, "Boric Acid Corrosion," specified in the GALL Report [Reference B-2]. 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 intended function, whereas the GALL program is limited to the Reactor Coolant System pressure boundary. The program will be enhanced to include portions of the Waste Management System within the scope of license renewal and to inspect and evaluate adjacent structures, systems, and components when leakage is identified. Commitment dates associated with enhancements to this program are contained in Appendix A.

Operating Experience and Demonstration

The Boric Acid Wastage Surveillance Program has been an ongoing program at St. Lucie since the 1980s. The program was implemented as a result of boric acid leaks experienced at St. Lucie and NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." This program addressed the Generic Letter program requirements including: (1) the determination of the principal locations where coolant leaks smaller than allowable Technical Specification limits could cause degradation of the pressure boundary, (2) methods for conducting examinations that are integrated into ASME Code VT-2 inspections conducted during system pressure tests, and (3) corrective actions to prevent recurrences of this type of leakage. The conservative philosophy established within the program has been successful in managing loss of material due to boric acid corrosion. It has provided for the timely identification of leakage and implementation of corrective actions as evidenced by work orders and condition reports. Since establishing this program, there have been no instances of boric acid corrosion that have impacted license renewal system intended functions.

Based upon the above, the implementation of the enhanced Boric Acid Wastage Surveillance Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.5 CHEMISTRY CONTROL PROGRAM

As identified in Chapter 3, the Chemistry Control Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

Auxiliary Feedwater and Condensate	Main Feedwater and Steam Generator Blowdown
Chemical and Volume Control	Main Steam, Auxiliary Steam, and Turbine
Component Cooling Water	Primary Makeup Water
Containment Cooling	Reactor Coolant
Containment Spray	Safety Injection
Demineralized Makeup Water (Unit 2 only)	Sampling
Diesel Generator and Support Systems	Turbine Cooling Water (Unit 1 only)
Fuel Pool Cooling	Ventilation
Instrument Air	

Structures (Structural components exposed to fluids)

Containments	Fuel Handling Buildings

The GALL Report [Reference B-2] contains three aging management programs addressed by the St. Lucie Chemistry Control Program. The GALL programs are: XI.M2, "Water Chemistry," XI.M21, "Closed-Cycle Cooling Water System," and XI.M30, "Fuel Oil Chemistry." A discussion of each of these programs relative to the comparable subprogram in the St. Lucie Chemistry Control Program is provided below.

3.2.5.1 CHEMISTRY CONTROL PROGRAM - WATER CHEMISTRY CONTROL SUBPROGRAM

The Water Chemistry Control Subprogram is consistent with the ten attributes of the Aging Management Program XI.M2, "Water Chemistry" in the GALL Report, except as noted. This subprogram was developed in accordance with the guidance in EPRI TR-105714, "PWR Primary Water Chemistry Guideline" [Reference B-12] and EPRI TR-102134, "PWR Secondary Water Chemistry Guideline" [Reference B-13]. The GALL program credits inspection of select components to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the period of extended operation. No special one-time inspections are required to be performed at St. Lucie.

Operating Experience and Demonstration

The Chemistry Control Program - Water Chemistry Control Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations, with technical input and concurrence from the U.S. NSSS vendors, as well as utility and water treatment experts.

The subprogram provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished through effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. Furthermore, the chemistry analyses are governed by the plant Quality Assurance Program to assure accurate results. Chemistry data is 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.

No special one-time inspections for the purpose of verifying the effectiveness of the Water Chemistry Control Subprogram are required for St. Lucie. Internal surfaces of components are visually inspected for loss of material and other aging effects during routine and corrective maintenance requiring equipment disassembly. If adverse conditions are identified, corrective action is taken via the corrective action program, which includes cause determination. In cases where the aging mechanism is not readily apparent, metallurgical analyses are typically performed. Review of numerous metallurgical reports for the systems and structures listed above, identified no instances of crevice corrosion or Chemistry Program related concerns.

Based upon the above, the continued implementation of the Chemistry Control Program - Water Chemistry Control Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.5.2 CHEMISTRY CONTROL PROGRAM - CLOSED-CYCLE COOLING WATER SYSTEM CHEMISTRY SUBPROGRAM

The Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the ten attributes of the Aging Management Program XI.M21, "Closed-Cycle Cooling Water System," in the GALL Report, except that this subprogram does not address surveillance testing and inspection. This subprogram was developed in accordance with the guidance in EPRI TR-107396, "Closed Cooling Water Chemistry Guideline" [Reference B-14]. The Intake Cooling Water Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program.

Operating Experience and Demonstration

The Chemistry Control Program - Closed-Cycle Cooling Water System Chemistry Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations, with technical input and concurrence from utility and water treatment experts.

The subprogram provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished through effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. Furthermore, the chemistry analyses are governed by the FPL Quality

Assurance Program to assure accurate results. Chemistry data is 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.

Based upon the above, the continued implementation of the Chemistry Control Program - Closed-Cycle Cooling Water System Chemistry Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.5.3 CHEMISTRY CONTROL PROGRAM - FUEL OIL CHEMISTRY SUBPROGRAM

This subprogram is plant-specific. The Chemistry Control Program - Fuel Oil Chemistry Subprogram addresses properties of new and stored fuel. This subprogram was developed in accordance with the guidance in ASTM D975-81, "Standard Specification for Fuel Oil." The Aging Management Program XI.M30, "Fuel Oil Chemistry," in the GALL Report contains additional aspects such as water removal and internal tank inspection. For St. Lucie Units 1 and 2, these aspects are performed as part of the Periodic Surveillance and Preventive Maintenance Program. The attributes for the Fuel Oil Chemistry Subprogram are provided below.

Scope of Program

The Chemistry Control Program - Fuel Oil Chemistry Subprogram is focused on managing the conditions that 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.

Preventive Actions

The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of the diesel fuel oil storage tanks and periodic draining of water collected at the bottom of the fuel oil storage and day tanks minimizes the amount of water and the length of contact time. Tank inspection and water removal are performed as part of the Periodic Surveillance and Preventive Maintenance Program. These measures are effective in mitigating internal corrosion.

Parameters Monitored or Inspected

The parameters monitored by the Chemistry Control Program - Fuel Oil Chemistry Subprogram are in accordance with ASTM Standards D4057-81, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" for guidance on oil sampling and D2276-83, "Particulate Contamination in Aviation Turbine Fuels," Method A or Annex A-2 for determination of particulates. Other ASTM standards are utilized for fuel oil testing as specified in the St. Lucie Units 1 and 2 Technical Specifications.

Detection of Aging Effects

Degradation of the diesel fuel oil system components cannot occur without exposure to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with applicable diesel fuel oil standards and periodic sampling in accordance with the Technical Specifications provide assurance that fuel oil contaminants are below acceptable levels.

Monitoring and Trending

Water and particulate contamination concentrations are monitored and trended. Based on the St. Lucie Units 1 and 2 Technical Specifications, monthly sampling and analysis of fuel oil chemistry is performed.

Acceptance Criteria

The acceptance criteria for the chemistry parameters required to be monitored and controlled are listed in the St. Lucie Units 1 and 2 Technical Specifications and the Chemistry Control Program implementing procedures.

Confirmation Process

Follow-up testing is performed to confirm satisfactory completion of corrective actions. These actions are documented in accordance with the corrective action program.

Operating Experience

The Chemistry Control Program - Fuel Oil Chemistry Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations.

The operating experience at St. Lucie Nuclear Plant has included particulate contamination due to a contaminated tanker truck transfer pump and hose. However, no instances of fuel oil system component failures attributed to contamination have been identified.

Based upon the above, the continued implementation of the Chemistry Control Program - Fuel Oil Chemistry Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is credited for ensuring the qualified life of electrical and I&C components within the scope of 10 CFR 50.49 (see Sections 2.5, 3.6, and 4.4 of this application).

Although not credited as an aging management program, the St. Lucie Environmental Qualification Program is consistent with the ten attributes of the Aging Management Program X.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in the GALL Report [Reference B-2]. The Environmental Qualification Program establishes the aging limit (qualified life) for each installed environmentally qualified device. The program ensures that the appropriate actions (repair, replacement, or refurbishment) are completed prior to a device exceeding its qualified life.

Environmental qualification evaluations are considered TLAAs for St. Lucie Units 1 and 2. The evaluations of these TLAAs are considered the technical rationale that the St. Lucie Units 1 and 2 CLBs will be maintained during the period of extended operation. Consistent with the NRC guidance for GSI-168, "Environmental Qualification of Electrical Components," no additional information is required to address this issue. In addition, no changes in activation energy were used in the TLAA evaluations performed.

Operating Experience and Demonstration

The Environmental Qualification Program is an ongoing program at St. Lucie that considers the best practices of industry organizations, vendors, and utilities. The program provides assurance that the environments to which installed devices are exposed will not exceed the qualified lives associated with the devices. This is accomplished through effective monitoring of key parameters (temperature and radiation) at established frequencies with well-defined acceptance criteria. The Environmental Qualification Program is governed by the FPL Quality Assurance Program to assure the requirements of 10 CFR 50.49 are maintained.

The overall effectiveness of the Environmental Qualification Program is supported by the excellent operating experience for systems, structures, and components that are influenced by the program. The program has been subject to periodic internal and external assessment activities that help to maintain highly effective control and facilitate continuous improvement.

Based upon the above, the continued implementation of the Environmental Qualification Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.7 FATIGUE MONITORING PROGRAM

As identified in Subsection 4.3.1, the Fatigue Monitoring Program is a confirmatory program for fatigue of Class 1 components in the Reactor Coolant System.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." At St. Lucie Units 1 and 2, cracking due to fatigue has not been identified as an aging effect requiring management. As such, the Fatigue Monitoring Program is considered a confirmatory program to ensure the fatigue TLAA analytical assumptions remain valid for the period of extended operation. The cycle monitoring procedure will be enhanced to require administrative action should the actual cycle count reach 80% of any design cycle limit. Commitment dates associated with enhancements to this program are contained in Appendix A.

Scope

The Fatigue Monitoring Program is designed to track design cycle occurrences to ensure the Reactor Coolant System components remain within their design fatigue usage limits. The specific fatigue analyses validated by this monitoring program are associated with the reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and Class 1 Reactor Coolant System piping.

Preventive Actions

The Fatigue Monitoring Program utilizes the systematic counting of design cycles to ensure that component design fatigue usage limits are not exceeded.

Parameters Monitored or Inspected

The design cycles monitored by the Fatigue Monitoring Program for the purposes of confirmation of Class 1 fatigue analyses are the fatigue-sensitive design cycles assumed in the Reactor Coolant System component design analyses. Additional design cycles are monitored as required by the plant Technical Specifications.

Detection of Aging Effects

The Fatigue Monitoring Program assures that the component design fatigue usage limits are not exceeded.

Monitoring and Trending

An administrative procedure provides the methodology for counting design cycles. The procedure will be enhanced to provide guidance as design cycle limits are approached.

Acceptance Criteria

The allowable number of design cycles are specified in the plant cycle monitoring procedure.

Confirmation Process

To prevent exceeding fatigue design limits, the cycle monitoring procedure will be enhanced to require administrative action as described in Subsection 4.3.1 should the actual cycle count reach 80% of any design cycle limit.

Operating Experience and Demonstration

The Fatigue Monitoring Program has been an ongoing program at St. Lucie since 1982, and has evolved over the many years of plant operation. As demonstrated in Subsection 4.3.1, the number of design cycles considered in the St. Lucie Units 1 and 2 CLBs fatigue analyses is sufficiently conservative to account for not only the current licensed term, but the extended period of operation as well. Confirmation will be accomplished through the Fatigue Monitoring Program.

The overall effectiveness of the Fatigue Monitoring Program is supported by independent review of the implementation and attributes of the program. A detailed review conducted by an outside organization, concluded the cycle monitoring procedure accurately identifies and classifies required Technical Specification and fatigue-sensitive design cycles, and provides an effective and consistent method for categorizing, counting, and tracking design cycles. The review concluded the program maintains sufficient information for each design cycle. In addition, a review of the design cycle counts documented to date was performed. Plant historical records were reviewed and compared against accumulated design cycle counts included in the administrative procedure. The review concluded that the accumulated design cycles documented conservatively reflect past plant operation.

Based upon the above, the continued implementation of the Fatigue Monitoring Program will provide reasonable assurance that the Reactor Coolant System components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.8 FIRE PROTECTION PROGRAM

As identified in Chapter 3, the Fire Protection Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Fire Protection System

Fire Rated Assemblies

This program is plant-specific. The GALL Report [Reference B-2] contains two programs, 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.

Scope

The Fire Protection Program is credited for managing the aging effects of loss of material due to corrosion (including selective leaching) for 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, halon system components, fire hydrants, vortex breakers, and sight glasses. This program is also credited for managing loss of material due to corrosion for fire doors.

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. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited for eliminating aging effects.

Parameters Monitored or Inspected

Surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material. 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.

Detection of Aging Effects

The detection of age-related degradation on external surfaces is determined by visual examination. Surfaces of components and structures are examined for coating degradation, rust, damage, deterioration, leakage, or corrosion. Functional testing and flushing of the systems clears away internal scale and corrosion products that could lead to blockage or obstruction of the system. 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.

Monitoring and Trending

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 is sufficient to identify effects of aging prior to compromising the integrity of the system or its intended function.

Acceptance Criteria

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.

Confirmation Process

Administrative procedures require verification that the affected fire protection feature be restored to normal configuration and that post maintenance testing, if required, be performed prior to return to service.

Operating Experience and Demonstration

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 overall effectiveness of the Fire Protection Program is demonstrated by the excellent operating experience of systems, structures, and components 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.

Based upon the above, the continued implementation of the Fire Protection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.9 FLOW ACCELERATED CORROSION PROGRAM

As identified in Chapter 3, the Flow Accelerated Corrosion Program is credited for aging management of selected components/commodity groups in the following systems:

Main Steam, Auxiliary Steam, and Turbine

Main Feedwater and Steam Generator Blowdown

Reactor Coolant (steam generator nozzles)

The current program is consistent with the ten attributes of the Aging Management Program XI.M17, "Flow-Accelerated Corrosion," specified in the GALL Report [Reference B-2]. This program is implemented in accordance with the EPRI guidelines provided in NSAC-202L-R2, Recommendations for an Effective Flow Accelerated Corrosion Program" [Reference B-15]. In addition, based on the aging management reviews performed, the St. Lucie program scope will be enhanced to include small bore piping associated with selected steam traps and drain lines that are potentially susceptible to flow accelerated corrosion and external general corrosion. Commitment dates associated with the enhancement to this program are contained in Appendix A.

Operating Experience and Demonstration

Wall thinning problems in single-phase systems have occurred in Main Feedwater and Condensate Systems and in two-phase piping in extraction steam lines and moisture separation reheater and feedwater heater drain lines. The Flow Accelerated Corrosion Program has been an ongoing formalized program at St. Lucie since the 1980s. The program was originally implemented as a result of steam leaks experienced throughout the industry, including FPL sites. This program was formalized in response to Generic Letter 89-09, "Flow Accelerated Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants." The Flow Accelerated Corrosion Program is continually upgraded based on industry experience and research.

The conservative philosophy established with the program has been successful in managing the loss of material due to flow accelerated corrosion. Various sections of susceptible piping are periodically examined using non-destructive examination techniques to determine the effects of flow accelerated corrosion. Results are evaluated and piping is either repaired or replaced as required. Branch connections are examined as St. Lucie or industry experience warrants.

Condition reports have been generated to document the results of ultrasonic examinations that identified piping wall thicknesses below the established screening criteria developed by the Flow Accelerated Corrosion Program. These condition reports resulted in repair, replacement, or subsequent inspection of the piping. Since 1996, there have been a small number of component replacements due to flow accelerated corrosion in the systems listed above. These include various Main Steam small bore and steam trap piping components and Steam Generator Blowdown piping components on Unit 1, and Steam Generator Blowdown System piping components on Unit 2.

Based upon the above, the implementation of the enhanced Flow Accelerated Corrosion Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.10 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

As identified in Chapter 3, the Intake Cooling Water Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Intake Cooling Water

Component Cooling Water

This program is plant-specific, although certain aspects of the Intake Cooling Water Inspection Program are comparable to Aging Management Program XI.M20, "Open-Cycle Cooling Water System," in the GALL Report [Reference B-2]. FPL credits the Intake Cooling Water System Inspection Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Boric Acid Wastage Surveillance Program for managing aging of Intake Cooling Water and Component Cooling Water components at St. Lucie Units 1 and 2.

Scope

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 functions of license renewal components. NRC Generic Letter 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.

Preventive Actions

The Intake Cooling Water System 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, non-destructive examination of heat exchanger tubes, and backflushing and inspection of the Intake Cooling Water strainers. External coatings are applied to portions of the Intake Cooling Water System to minimize corrosion. However, coatings are not credited in the determination of aging effects requiring management.

Parameters Monitored or Inspected

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 Component Cooling Water heat exchangers are monitored during normal operation to verify heat transfer capability. Tube integrity of Component Cooling Water heat exchangers is monitored by periodic non-destructive examinations to ensure early detection of aging effects.

Detection of Aging Effects

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 Component Cooling Water heat exchangers is conducted to provide for early identification of fouling and degraded conditions that could impact the ability of the Component Cooling Water heat exchangers to perform their intended function. Periodic tube inspections and cleaning are performed to assure heat exchanger performance and integrity.

Monitoring and Trending

Inspection scope, method, and testing frequencies are in accordance with FPL commitments under Generic Letter 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. Component Cooling Water 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.

Acceptance Criteria

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.

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.

Confirmation Process

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

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.

Based upon the above, the continued implementation of the Intake Cooling Water System Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.11 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

As identified in Chapter 3, 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	

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. The program will be enhanced to include inspections of components such as filter housings, radiator fins, flexible hoses, door seals, and expansion joints. Commitment dates associated with the enhancements to this program are contained in Appendix A.

Scope

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 for 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 systems, structures, and components. 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.

Preventive Actions

Preventive measures include charging pump block internal inspection (Unit 2 only), oil sampling and water removal, and replacement of specific structural components and component groups based on operating experience.

Parameters Monitored or Inspected

Surface conditions of systems, structures, and components 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 Intake Cooling Water 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.

Detection of Aging Effects

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.

Monitoring and Trending

The inspections, replacements, and sampling activities associated with this program are performed on 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 effect being managed, and plant operating experience. Examples of inspections and activities included in the Periodic Surveillance and Preventive Maintenance Program are provided below:

- Inspection of diesel generator flexible hoses for cracking.
- Inspection for loss of seal of air tight door seals and gaskets.

The frequency of preventive maintenance tasks may be adjusted, as necessary, based on future plant-specific performance and/or industry experience.

Acceptance Criteria

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 include:

- Inspections for loss of material provide guidance that require 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 on a specified frequency based on plant experience or equipment supplier recommendations.

Confirmation Process

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

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 is supported by the improved systems and structures material condition and reliability, documented by internal as well as external assessments during the last several years.

Based upon the above, the implementation of the enhanced Periodic Surveillance and Preventive Maintenance Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.12 REACTOR VESSEL INTEGRITY PROGRAM

As identified in Chapter 3, the Reactor Vessel Integrity Program is credited for aging management of the reactor vessels in the Reactor Coolant Systems.

This program is plant-specific. The Aging Management Program XI.M31, "Reactor Vessel Surveillances," in the GALL Report [Reference B-2] identifies in the Evaluation and Technical Basis section that reactor vessel surveillance programs are plant-specific and require further staff evaluation for license renewal.

The Reactor Vessel Integrity Program which manages reactor vessel irradiation embrittlement, encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Each subprogram described below.

The program documentation will be enhanced to generate a standard specification that documents all aspects of the Reactor Vessel Integrity Program. Commitment dates associated with the enhancement of this program are contained in Appendix A.

3.2.12.1 REACTOR VESSEL INTEGRITY PROGRAM - REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION SUBPROGRAM

The extended period of operation will require revision to the St. Lucie Units 1 and 2 surveillance capsule removal schedules. The information provided below is intended to satisfy the requirements of 10 CFR 50, Appendix H, for NRC review and approval of the revised surveillance capsule schedules.

The 40-year reactor vessel surveillance capsule removal schedules are presented in the current Unit 1 UFSAR Table 5.4-3 and Unit 2 UFSAR Table 5.3-9. These schedules provide for capsule removal when fluence levels can be obtained to predict the end of life (40 years) properties of the vessel beltline materials.

The requirements for new surveillance schedules are identified in 10 CFR 50, Appendix H. The method of determining the new surveillance schedules is outlined in Section XI.M31 of the GALL Report. The guidance indicates the program should follow ASTM E185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2, and provide data for the reactor vessel materials with a fluence equivalent to 60 years.

The St. Lucie Unit 1 subprogram is a five capsule withdrawal schedule program, in accordance with ASTM E185-82.

The Unit 1 surveillance capsules contain base material from the lower shell plate and weld metal from the intermediate- to lower-shell girth weld. Three capsules have already been removed. The limiting vessel material is the lower shell axial weld, which is contained in the Beaver Valley Unit 1 surveillance program. This program has been evaluated and accepted by the NRC to be representative of the St. Lucie Unit 1 lower-shell axial weld seams [Reference B-16]. The Beaver Valley Unit 1 surveillance program has test data [Reference B-17] that bound the ¼T (one-quarter vessel thickness) fluence for the St. Lucie Unit 1 limiting weld material.

The St. Lucie Unit 1 removal times are based on the accumulated fluence values in ASTM E185-82. The NRC has accepted the accumulated fluence approach previously for the St. Lucie Unit 1 capsule schedule [Reference B-18].

The St. Lucie Unit 2 program is a four capsule withdrawal schedule program, in accordance with ASTM E185-82.

The capsules that have been removed are reviewed relative to the ASTM E185-82 criteria so that the remaining capsule and schedule can yield the most bounding data for future operation of the reactor vessel. The removal times are based on the accumulated fluence values in ASTM E185-82. The Unit 2 surveillance capsules contain material from intermediate shell plate, which is the controlling material for this plate-limited vessel.

The Units 1 and 2 reactor vessel surveillance capsule removal schedules require revision to provide meaningful data for the 60-year license renewal period. The proposed schedules were revised in accordance with ASTM E185-82 and GALL Report recommendations.

Appendices A1 and A2 include the changes to the surveillance capsule schedules listed in Unit 1 UFSAR Table 5.4-3, and Unit 2 UFSAR Table 5.3-9.

The attributes described below are based on the revised surveillance capsule schedules.

Scope

This subprogram manages the aging effect of reduction in fracture toughness on the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens.

Preventive Actions

This is a monitoring subprogram; as such, preventive actions are not required.

Parameters Monitored or Inspected

Monitored parameters include fracture toughness and tensile strength as measured by Charpy V-notch and tensile test results for irradiated specimens of reactor vessel plate and weld materials. Additionally, accumulated neutron fluence is monitored utilizing surveillance capsule dosimetry.

Detection of Aging Effects

Fracture toughness values that are lower than predicted provide indications of unexpected accelerated aging of the reactor vessel materials. Fracture toughness values are determined using calculations of vessel fluence and empirical results from Charpy V-notch testing of irradiated specimens.

Monitoring and Trending

Empirical material fracture toughness and accumulated neutron fluence data are obtained from the vessel irradiated specimen surveillance. This data and the trend curves from NRC

Regulatory Guide 1.99 provide the basis for the value for reference temperature for nil-ductility transition (RT_{NDT}) and for determining reactor vessel heatup and cooldown limits. These data are monitored and trended to ensure continuing reactor vessel integrity. Both Units contain a sufficient number of capsules to monitor fluences for the extended period of operation. The surveillance capsule withdrawal schedules are specified in Chapter 5 of the Unit 1 UFSAR Supplement provided in Appendix A1, and Chapter 5 of the Unit 2 UFSAR Supplement provided in Appendix A2, and have been revised for the extended period of operation as necessary. Future decisions concerning the frequency of withdrawal of surveillance capsules will be based on changes in fuel type or fuel loading pattern.

Acceptance Criteria

Values of RT_{NDT} are calculated based on test results and compared with Regulatory Guide 1.99 trend curves. Surveillance data that fall outside of the defined "credible range" may require further evaluation. The reference temperature for pressurized thermal shock (RT_{PTS}) values must also be within the screening criteria of 10 CFR 50.61.

Confirmation Process

Periodic testing of the vessel irradiated specimens provides advance indication of future material deterioration. Present testing can be used to validate the accuracy of previous predictions.

Operating Experience and Demonstration

The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram is NRC approved, meets the requirements of 10 CFR 50, Appendix H, and has been in effect since the initial plant start-up. This subprogram has been updated over the years and has provided experience in addressing reduction in fracture toughness. St. Lucie Units 1 and 2 pressure-temperature limit curves have been updated using results from the vessel surveillance capsule specimen evaluations. St. Lucie Units 1 and 2 have been evaluated to have values for RT_{PTS} that are within the acceptance criteria of 10 CFR 50.61.

3.2.12.2 REACTOR VESSEL INTEGRITY PROGRAM - FLUENCE AND UNCERTAINTY CALCULATIONS SUBPROGRAM

Scope

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates and welds.

Preventive Actions

This is a monitoring program; as such, preventive actions are not required.

Parameters Monitored or Inspected

The monitored parameters are the reactor vessel accumulated neutron fluence values, which are currently predicted based on analytical models meeting the requirements of Draft NRC Regulatory Guide DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," and are benchmarked using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram.

Detection of Aging Effects

Accumulated fluence values in excess of predicted values can result in lower fracture toughness values in reactor vessel materials due to irradiation embrittlement. The potential for these effects is determined using neutron 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.

Monitoring and Trending

Neutron fluence and uncertainty calculations are performed to predict the accumulated 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.

Acceptance Criteria

The results of the fluence uncertainty calculations are to be within the NRC suggested limit of ±20%. Calculated fluence values for fast neutrons (above 1.0 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.

Confirmation Process

The analytical predictions of reactor vessel fast neutron fluence are validated using dosimeter data from the irradiated specimens. Cavity (ex-vessel) dosimetry may also be used to supplement surveillance capsule data.

Operating Experience and Demonstration

The neutron fluence and uncertainty calculations for St. Lucie Units 1 and 2 have been performed in accordance with the guidelines of Draft Regulatory Guide DG-1053 and validated using data obtained from the capsule dosimetry. The results of the fluence uncertainty values are to be within the NRC-suggested limit of ±20%. This has been validated by the comparison of the calculated fluence values with measurement 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.

FPL Letter L-2001-65 [Reference B-19], Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, April 19, 2001, provided information in response to request for additional information (RAI) 3.9.13.2-1 concerning the database, the data processing (including computer codes) and the associated calculations that demonstrate adherence to the requirements of Draft Regulatory Guide DG-1053. For St. Lucie Units 1 and 2, the methodology is essentially the same as identified in the RAI response, but the databases are plant-specific.

3.2.12.3 REACTOR VESSEL INTEGRITY PROGRAM - MONITORING EFFECTIVE FULL POWER YEARS SUBPROGRAM

Scope

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessels to ensure that the pressure-temperature limit curves and end-of-life reference temperatures are not exceeded.

Preventive Actions

This is a monitoring program; as such, preventive actions are not required.

Parameters Monitored or Inspected

The monitored parameters are the reactor vessels' equivalent time at full power in EFPYs.

Detection of Aging Effects

EFPY calculations are utilized for the prediction of total accumulated fast neutron fluence and the determination of the reduction in fracture toughness of reactor vessel critical materials.

Monitoring and Trending

This subprogram monitors the accumulated reactor vessel EFPYs to be used in predicting the accumulated 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 pressure-temperature limit curves for the next operating cycle.

Acceptance Criteria

Calculated EFPYs shall not exceed the St. Lucie Units 1 and 2 Technical Specification limits for the validity of the pressure-temperature limit curves.

Confirmation Process

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. Data are collected for both St. Lucie reactor vessels. The EFPY calculations are used to verify the continued validity of the pressure-temperature limit curves and PTS values.

Operating Experience and Demonstration

The EFPYs calculations are used to verify the continued validity of the pressure-temperature limit curves and PTS values. Plant-specific experience has proven this an effective process to assure continued validity of the pressure-temperature curves and the PTS values.

3.2.12.4 REACTOR VESSEL INTEGRITY PROGRAM - PRESSURE-TEMPERATURE LIMIT CURVES SUBPROGRAM

Scope

This subprogram provides pressure-temperature limit curves for the St. Lucie Units 1 and 2 reactor vessels to establish the Reactor Coolant System normal operating limits.

Preventive Actions

Pressure-temperature limit curves are provided to prevent or minimize the potential of damaging the reactor vessel materials. The curves are included in the Technical Specifications and applicable operating procedures.

Parameters Monitored or Inspected

The pressure-temperature limit curves specify maximum allowable pressure as a function of Reactor Coolant System temperature. Reactor Coolant System pressures and temperatures at St. Lucie Units 1 and 2 are maintained within these limits.

Detection of Aging Effects

The pressure-temperature limit curves are not provided for the detection of aging effects, but rather to prevent or minimize potential for damage to the reactor vessel materials.

Monitoring and Trending

The pressure-temperature limit curves are valid for a period expressed in EFPYs. These curves shall be updated prior to exceeding the EFPYs for which they are valid. The time period for updating pressure-temperature limit curves may change if conditions such as changes in fuel type or fuel loading pattern occur.

Acceptance Criteria

NRC approved pressure-temperature limit curves must be in place for continued plant operation.

Confirmation Process

The pressure-temperature limit curves are verified in accordance with the FPL Quality Assurance Program. These pressure-temperature limit curves are NRC approved prior to use, and validated using data obtained from the surveillance capsule specimens.

Operating Experience and Demonstration

FPL utilizes pressure-temperature limit curves for St. Lucie Units 1 and 2 that have been updated using the results of data obtained from the surveillance capsules. The pressure-temperature limit curves have been developed utilizing an industry methodology that has been approved by the NRC. The pressure-temperature limit curves provide sufficient operating margin while preventing or minimizing the potential for damage to the reactor vessel materials.

Based on the above, the implementation of the enhanced Reactor Vessel Integrity Program provides an effective program for managing the aging effect of reduction in fracture toughness on the reactor vessels such that the components within the scope of license renewal will perform their intended functions in accordance with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.13 STEAM GENERATOR INTEGRITY PROGRAM

As specified in Chapter 3, the Steam Generator Integrity Program is credited for aging management of the steam generators in the Reactor Coolant Systems.

The Steam Generator Integrity Program is consistent with the ten attributes of Aging Management Program XI.M19, "Steam Generator Tube Integrity," specified in the GALL Report [Reference B-2]. In addition, the St. Lucie program scope includes the Unit 2 steam generator tube support lattice bars, and credits sludge lancing as a preventive action for secondary-side steam generator tube degradation, and bundle flushing to minimize flow accelerated corrosion of the Unit 2 carbon steel tube support lattice bars.

Operating Experience and Demonstration

The Steam Generator Integrity Program has been effective in ensuring timely detection and correction of the aging effects of cracking and loss of material in steam generator tubes. Tube plug cracking appears to have been related to susceptible heats of material and improper heat treatment, or improper installation.

The Steam Generator Integrity Program is consistent with the guidance provided in NEI 97-06, "Steam Generator Program Guidelines" [Reference B-20], which has undergone extensive industry and NRC review. The current steam generator inspection activities have been evaluated against industry recommendations provided by EPRI and the steam generator suppliers. The overall effectiveness of the program is supported by the excellent steam generator operating experience and favorable inspection results.

Results of previous steam generator inspections and the assessment of potential steam generator aging mechanisms have been evaluated for St. Lucie Units 1 and 2. The evaluations provide a discussion of the design features present in the St. Lucie steam generators that minimize the potential for rapid steam generator degradation. These design features, in addition to the currently specified inspections, ensure that the steam generator intended functions will be maintained in the period of extended operation.

Based on the above, the continued implementation of the Steam Generator Integrity Program provides reasonable assurance that the aging effects will be managed such that the steam generator components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

3.2.14 SYSTEMS AND STRUCTURES MONITORING PROGRAM

As identified in Chapter 3, the Systems and Structures Monitoring Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

Auxiliary Feedwater and Condensate	Intake Cooling Water
Chemical and Volume Control	Main Feedwater and Steam Generator Blowdown
Component Cooling Water	Main Steam, Auxiliary Steam, and Turbine
Containment Cooling	Miscellaneous Bulk Gas Supply
Containment Isolation	Primary Makeup Water
Containment Spray	Safety Injection
Diesel Generator and Support Systems	Turbine Cooling Water (Unit 1)
Fire Protection	Ventilation
Fuel Pool Cooling	Waste Management
Instrument Air	

Structures

Component Cooling Water Areas	Intake Structures
Condensate Storage Tank Enclosures	Reactor Auxiliary Buildings
Containments	Steam Trestle Areas
Diesel Oil Equipment Enclosures	Turbine Buildings
Emergency Diesel Generator Buildings	Ultimate Heat Sink Dam
Fuel Handling Buildings	Yard Structures
Intake, Discharge, and Emergency Cooling Canals	

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program XI.S6, "Structures Monitoring Program." The structural aspects of the Systems and Structures Monitoring Program are consistent with the GALL program. However, the St. Lucie program includes the systems and structures listed above.

The program will be enhanced to provide guidance for the following: managing the aging effects of inaccessible concrete, performing inspections of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. Commitment dates associated with the enhancements to this program are contained in Appendix A.

Scope

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling (mechanical components only), loss of seal, and change in material properties for the systems and structures listed above. The program provides for visual inspection and examination of accessible surfaces of systems, structures, and components, including welds and bolting. Inspection of insulated piping and equipment is performed by removal of the insulation to gain visual access to the surfaces being inspected. As an alternative, computed radiography may be used to determine if significant external corrosion is present on insulated equipment. The program also includes leak inspection of selected Intake Cooling Water System and Chemical and Volume Control System valves, piping, and fittings.

Preventive Actions

External surfaces of carbon steel valves, piping, and fittings; cast iron equipment; and surfaces of steel structures and supports are coated to minimize corrosion. However, coatings are not credited in the determination of aging effects requiring management.

Parameters Monitored or Inspected

Surface conditions of structures, system components, piping, and supports are monitored through visual examinations to determine the existence of external corrosion and in some cases, internal corrosion. The monitoring of concrete and components is consistent with the guidelines provided in ACI 349.3R-96, "Evaluation of Existing Nuclear Safety Related Concrete Structures" and SEI/ASCE 11-99, "Guideline for Structural Condition Assessment of Existing Buildings." The parameters monitored are selected based on industry and plant experience to ensure that aging degradation that could lead to loss of intended function will be identified and addressed. Concrete and masonry parameters monitored include exposed rebar, cracking, rust bleeding, spalling, scaling, other surface irregularities, and settlement. Steel structure parameters monitored include corrosion, flaking, pitting, gouges, cracking, and other surface irregularities. System commodity and component surface conditions are inspected for corrosion (e.g., general corrosion and pitting), cracking, fouling (mechanical components only), other surface irregularities, and leakage for selected systems.

Flexible connectors are monitored for cracking due to embrittlement, and air-cooled heat exchangers are monitored for fouling. Leakage inspections of valves, piping, and fittings at selected locations of the Intake Cooling Water Systems are utilized to detect the presence of internal corrosion. Inspection of weatherproofing materials for deterioration is performed. Aging management of structural components that are inaccessible for inspection is accomplished by inspecting accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components.

Detection of Aging Effects

The aging effects of loss of material, cracking, fouling (mechanical components only), loss of seal, and change in material properties are detected by visual inspection of surfaces for evidence of degradation or leakage.

Monitoring and Trending

Detailed structural and system or component material condition inspections are performed in accordance with approved plant procedures. The results of the visual inspections for systems, structures, and components are documented. The frequency of inspections may be adjusted, as necessary, based on inspection results and industry experience. For insulated piping, a small sample of the sections of systems that operate at less than 212^{o}F will be selected for inspection on the basis of piping geometry, and potential exposure to rain or other conditions that could result in wetting of the insulation.

The inspection schedule varies depending on the system, structure, or component being inspected. These frequencies are based on St. Lucie plant experience considering degradation rates and the ability of a structure or component to accommodate degradation without a loss of intended function. The frequency of inspections may be adjusted, as necessary, based on future inspection results and industry experience.

Personnel responsible for the performance of inspections and evaluation of inspection results are qualified in accordance with the Engineering Training Program.

Acceptance Criteria

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 systems, structures, and components within the scope of this program. The guidance includes specific parameters to be monitored and criteria to be used for evaluating identified degradation. In addition, the procedures provide sample forms to be used to document the analysis and the assessment, and a system checklist for documenting relevant information from a system walkdown.

Confirmation Process

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

The Systems and Structures Monitoring Program has been an ongoing program at St. Lucie Nuclear Plant and has been enhanced over the years to include the best practices recommended by industry guidance. Additionally, the Systems and Structures Monitoring Program supports implementation of the NRC Maintenance Rule (10 CFR 50.65).

Systems, structures, and components have been periodically inspected for material condition at St. Lucie Units 1 and 2. As part of implementation of the Maintenance Rule, baseline inspections were performed. Periodic inspections continue to be performed as part of this program. Degraded conditions are documented in accordance with the corrective action program. As part of the corrective action program, actions to prevent recurrence are identified, such as plant modifications or program enhancements to address the affected item as well as related generic implications. Periodic evaluations are performed to assess and initiate enhancements to plant programs.

Based on the above, the continued implementation of the Systems and Structures Monitoring Program provides reasonable assurance that the aging effects will be managed such that the systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

4.0 REFERENCES

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B-2 NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," U.S. Nuclear Regulatory Commission, April 2001.

B-3 NEI 95-10, Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Nuclear Energy Institute, March 2001.

B-4 NEI letter to U. S. Nuclear Regulatory Commission, "Demonstration Application Using the Generic Aging Lessons Learned Report," May 24, 2001.

B-5 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2 and Turkey Point Units 3 and 4, Docket Nos. 50-335, 50-389, 50-250 and 50-251, Response to Bulletin 2001-01," L-2001-198, September 4, 2001.

B-6 Kundalkar, R. S. (FPL) letter to U. S. Nuclear Regulatory Commission, "St. Lucie Units 1 and 2, Docket Nos. 50-335, 50-389, Supplemental Response to NRC Bulletin 2001-01," L-2001-247, November 1, 2001.

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B-9 ASME Code Case N-509, "Alternative Requirements for the Selection and Examinations of Class 1, 2, and 3 Integrally Welded Attachments Section XI Division 1," November 25, 1992.

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B-13 EPRI TR-102134, "PWR Secondary Water Chemistry Guidelines," Revision 5, Electric Power Research Institute.

B-14 EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," Electric Power Research Institute, October 1997."

B-15 NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program, Electric Power Research Institute," dated April 8, 1999.

B-16 Wiens, L. A. (NRC) letter to Plunkett, T. F. (FPL) and Attached Safety Evaluation, "St. Lucie Units 1 and 2 - Pressurized Thermal Shock Evaluation (TAC NO. M95484 and M95485), October 27, 1997.

B-17 WCAP-15571, "Analysis of Capsule Y from First Energy Company, Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program," Westinghouse Electric Company, November 2000.

B-18 Norris, J (NRC) to Goldberg, J. H. (FPL) and Attached Safety Evaluation, "St. Lucie Unit 1 - Issuance of Amendment 100 RE: Reactor Vessel Material Surveillance," December 6, 1989.

B-19 Hovey, R. J. (FPL) letter to U. S. Nuclear Regulatory Commission, "Response to Request for Additional Information for the Review of the Turkey Point Units 3 and 4 License Renewal Application," L-2001-65, April 19, 2001.

B-20 NEI 97-06, "Steam Generator Program Guidelines," Nuclear Energy Institute, November 1997.

APPENDIX C

PROCESS FOR IDENTIFYING AGING EFFECTS REQUIRING MANAGEMENT FOR NON-CLASS 1 COMPONENTS

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1.0 INTRODUCTION

FPL utilized industry guidance, developed by the Babcock and Wilcox (B&W) Owners Group, for determining aging effects requiring management for the non-Class 1 components and steel in fluids associated with structural components. The guidance was reviewed for applicability, and tailored to address St. Lucie Units 1 and 2 materials and environments and to incorporate specific aging mechanisms/effects based upon plant experience (i.e., lessons learned). This appendix summarizes the process for identification of aging effects requiring management for non-Class 1 components.

The potential aging effects evaluated include the following:

- loss of material
- cracking
- fouling
- loss of mechanical closure integrity
- reduction in fracture toughness
- distortion/plastic deformation

Internal operating environments evaluated are:

- treated water - primary
- treated water - secondary
- treated water - borated
- treated water - other
- raw water - salt water
- raw water - city water
- raw water - drains
- air/gas
- fuel oil
- lubricating oil

External operating environments evaluated are:

- outdoor
- indoor - not air conditioned
- indoor - air conditioned
- containment air
- borated water leaks
- buried (above groundwater elevation)

- embedded/encased (in concrete)

A component is considered susceptible to a wetted environment when the component is submerged, has the potential to pool water, or is subject to external condensation.

For components that are submerged, an applicable internal environment listed above may be specified.

Where wetted conditions exist (e.g., due to condensation), the environment is annotated accordingly.

Note: Other than borated water leaks, fluid leakage is not considered in the aging management review process. Fluid leakage is considered an event-driven condition and not a normal operating condition. As noted in Christopher I. Grimes (NRC) letter to Douglas J. Walters (NEI), June 5, 1998, aging effects from abnormal events need not be postulated for license renewal [Reference C-1].

2.0 COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

In accordance with 10 CFR 54 and NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," [Reference C-2] Appendix B, only passive components are in the scope of review. Within the systems that are in the scope of license renewal, the following are typical components subject to aging management review:

ductwork	heat exchangers	pump casings
expansion joints	mechanical closure bolting	steam traps
flexible hoses	orifices and flow elements	tanks/vessels
filters, strainers	piping, tubing, and fittings	valve bodies and bonnets
fuel handling equipment	fuel storage racks	

Many of the components within the scope of license renewal contain gaskets, packing, and seals. However, these items, defined as consumables, are not subject to aging management review since they do not support the component intended functions as established by design codes and are not long-lived.

3.0 MATERIALS USED IN NON-CLASS 1 COMPONENTS

The following materials are present in non-Class 1 components within the scope of license renewal:

aluminum	titanium	rubber
aluminum alloy	copper	Neoprene
stainless steel (wrought and cast)	copper alloys (brass, copper nickel, bronze, aluminum brass, aluminum bronze)	vinyl ester
nickel alloy		glass
		plastic
carbon steel (plain and galvanized)	Monel	Plexiglas
		rubber coated cloth
cast iron	low alloy steel	fiberglass

Note that some components contain internal and external coatings or linings. For example, Intake Cooling Water piping is cement lined and some valves are rubber lined. These features perform a preventive function, but are not credited for the elimination of aging effects requiring management.

4.0 ENVIRONMENTS

4.1 INTERNAL ENVIRONMENTS

4.1.1 TREATED WATER

Treated water is demineralized water and is the base water for all clean systems. Depending on the system, treated water may involve additional processing. Treated water can be deaerated, and can include corrosion inhibitors, biocides, boric acid, or a combination of these treatments. Within this application, treated water has been subdivided into the following groups based on the chemistry of the water.

- <u>Treated water - primary</u> - Normal operating Reactor Coolant System chemistry
- <u>Treated water - secondary</u> - Normal operating secondary chemistry, including Main Steam, Turbine, Feedwater, Auxiliary Feedwater, Condensate, and Blowdown Systems
- <u>Treated water - borated</u> - Systems that contain borated water except those included in treated water - primary, including Chemical and Volume Control, Spent Fuel Cooling, Emergency Core Cooling, and Sampling Systems
- <u>Treated water - other</u> - All other treated water systems, including Component Cooling Water, Turbine Cooling Water, Emergency Diesel Generator Cooling, Primary Makeup Water, and Unit 2 Demineralized Makeup Water Systems. With the exception of makeup water, all systems utilize corrosion inhibitors and, in some cases, biocides.

Aging effects for materials typically found in treated water environments are summarized in Sections 3.2 though 3.5 of this application.

4.1.2 RAW WATER

For St. Lucie Units 1 and 2, raw water constitutes the salt water that comes from the ocean through the intake canal and is used for the main condensers and Intake Cooling Water System, the salt water from Big Mud Creek that is used for the Ultimate Heat Sink, and the city water that is used for the Fire Protection and Service Water Systems. In general, the water has been rough filtered to remove large particles and may contain a biocide additive for control of micro-organisms and macro-organisms. Although city water is purified, it is conservatively classified as raw water for the purposes of aging management review. Within this Application, raw water has been subdivided into the following groups based on the chemistry of the water.

- <u>Raw water - salt water</u> - Salt water used for the main condensers and as the ultimate heat sink
- <u>Raw water - city water</u> - Potable water supplied to the water treatment plant, and the Service Water and the Fire Protection Systems

- Raw water - drains - 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

Aging effects for materials typically found in raw water environments are summarized in Sections 3.2, 3.3, and 3.5 of this application.

4.1.3 AIR/GAS

This environment includes atmospheric air, dry/filtered instrument air, nitrogen, carbon dioxide, hydrogen, and Halon.

Air is composed of mostly nitrogen and oxygen with smaller fractions of various other constituents. The internal surfaces of a majority of components are, at some time, exposed to air. Where air is the intended internal environment, it is supplied in either its natural state or in a dry condition.

Nitrogen is an inert gas used in many nuclear power plant applications to place components in a dry lay-up condition or to provide a cover gas to prevent exposure to oxygen.

Carbon dioxide is a colorless, odorless incombustible gas. Without the presence of moisture, the gaseous carbon dioxide is not a significant contributor to corrosion or other aging effects.

Hydrogen is a colorless, odorless combustible gas.

Halon is a halogenated extinguishing agent used in the Fire Protection System for its ability to chemically react with fire and smother flames. Halon is a non-corrosive gas.

Aging effects for materials typically found in air/gas environments are summarized in Sections 3.2 through 3.4 of this application. Where wetted conditions are determined to exist (e.g., due to condensation), the environment description is amended accordingly, and potential aging effects are addressed.

4.1.4 FUEL OIL

This includes fuel oil for the emergency diesel generators. Fuel oil within the scope of license renewal is No. 2 diesel oil. Diesel fuel oil is delivered to St. Lucie Nuclear Plant in tanker trucks and is stored in large tanks to provide an onsite supply of diesel fuel for a specified period of emergency diesel generator operating time. The fuel oil is supplied to the emergency diesel engines through pumps, valves, and piping. Strainers, filters, and other equipment assure that the diesel fuel supplied to the engines is clean and free of contaminants. Aging effects for materials typically found in fuel oil environments are summarized in Section 3.3 of this application.

4.1.5 LUBRICATING OIL

This environment is the lubricating oil for emergency diesel generators, pumps, and other components. Also included in this environment are hydraulic oils used in valve actuators. Lubricating oils within the scope of license renewal are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication. Aging effects for materials typically found in lubricating oil environments are summarized in Sections 3.3 and 3.4 of this application.

4.2 EXTERNAL ENVIRONMENTS

4.2.1 OUTDOOR

The outdoor environment is characterized by moist, salt-laden atmospheric air, temperature 27°F-93°F, 73% average humidity, and exposure to weather, including precipitation and wind. Aging effects for materials typically found in outdoor environments are summarized in Sections 3.2 through 3.6 of this application.

4.2.2 INDOOR - NOT AIR CONDITIONED

This includes atmospheric air, a temperature of 104°F maximum (110°F maximum in the Unit 2 Electrical Equipment Room), 73% average humidity, and no exposure to weather. Aging effects for materials typically found in indoor - not air conditioned environments are summarized in Sections 3.2 through 3.6 of this application.

4.2.3 INDOOR - AIR CONDITIONED

This includes atmospheric air with a specific temperature/humidity range dependent upon the building/room, and involves no exposure to weather. Typically, the temperature is 70°F-80°F, and the humidity is 45%-55%. Aging effects for materials typically found in indoor – air conditioned environments are summarized in Section 3.5 of this application.

4.2.4 CONTAINMENT AIR

This includes atmospheric air, a temperature of 120°F maximum, 73% average humidity, radiation total integrated dose rate of 2 rads per hour (excluding equipment located inside the reactor cavity), and no exposure to weather. Aging effects for materials typically found in containment air environments are summarized in Sections 3.2 through 3.5 of this application.

4.2.5 BORATED WATER LEAKS

This environment includes exposure to leakage from borated water systems. The concentrations of boric acid in the Reactor Coolant System and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel.

Aging effects for materials exposed to borated water leak environments are summarized in Sections 3.2 through 3.6 of this application.

4.2.6 BURIED

Above groundwater elevation, this environment involves exposure to soil/fill. Below groundwater elevation, this environment involves exposure to soil/fill and groundwater. Groundwater contains aggressive chemicals that can attack susceptible materials. Although all buried piping and mechanical components are above groundwater elevation, buried components are assumed to be susceptible to corrosion. The only exception to this is buried piping located under a concrete slab. In this case, it is unlikely that the surface of the pipe will be exposed to a wetted environment and, therefore, it is not considered susceptible to external corrosion. Aging effects for materials typically found in buried environments are summarized in Sections 3.3 through 3.6 of this application.

4.2.7 EMBEDDED/ENCASED

This environment is associated with reinforcing or embedded steel or piping in concrete. Aging effects for materials typically found in embedded/encased environments are summarized in Sections 3.3 through 3.5 of this application.

5.0 POTENTIAL AGING EFFECTS

Potential aging effects were determined based on materials and environments. Aging effects are considered to require management if the effects could cause loss of component intended function during the period of extended operation. The potential aging effects and associated mechanisms evaluated for non-Class 1 components are as discussed below.

5.1 LOSS OF MATERIAL

Loss of material may be due to general corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion/corrosion, erosion, microbiologically influenced corrosion, selective leaching, wear, and aggressive chemical attack.

General corrosion is the result of a chemical or electrochemical reaction between the material and the environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution, and sometimes corrosion product buildup. General corrosion on components exposed to air tends to form a protective oxide film on the components that prevents further significant corrosion. This is typically true for components not exposed to other sources of moisture such as rain, condensation, or frequent leakage. Wrought austenitic stainless steel, copper, copper alloys, CASS, and nickel-based alloys are not susceptible to general corrosion except when subjected to aggressive environments. Carbon and low alloy steels are susceptible to external general corrosion in all areas with the exception of those exposed to a controlled, air conditioned environment, and those applications where the metal temperature is greater than 212°F. Additionally, galvanized carbon steel is not considered susceptible to general corrosion except where buried, submerged in fluid, or subject to wetting other than humidity, such as salt spray.

Pitting corrosion is a form of localized attack that results in depressions in the metal. For treated water systems, oxygen is required for initiation of pitting corrosion with contaminants, such as halogens or sulfates, required for continued metal dissolution. Pitting corrosion occurs when passive films in local areas attack passive materials. Once a pit penetrates the passive film, galvanic conditions occur because the metal in this pit is anodic relative to the passive film. Maintaining adequate flow rate over this exposed surface of a component can inhibit pitting corrosion. However, stagnant or low flow conditions are assumed to exist in all systems where dead legs of piping, such as vents or drains, exist. Pitting corrosion is more common with passive materials, such as austenitic stainless steels, than with non-passive materials. Most materials of interest are susceptible to pitting corrosion under certain conditions. For treated water environments, stainless and carbon steels are assumed susceptible to pitting in the presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb when dissolved oxygen is in excess of 100 ppb. However, like general corrosion, moisture must be present, and those metals exposed to a controlled, air conditioned environment or an operating temperature greater than 212°F are not susceptible to external pitting corrosion. Because pitting of stainless steel material in an outdoor environment at St. Lucie Nuclear Plant is dependent on its location within the plant site, these materials were evaluated based upon experience and visual inspections. Typically, stainless steel materials located near the plant discharge canal are more susceptible due to the salt spray environment. Additionally, bronze and brass are considered susceptible to pitting when the zinc content is greater than 15%, and aluminum bronze is considered susceptible to pitting when the aluminum content is greater than 8%.

Loss of material due to galvanic corrosion can occur only when materials with different electrochemical potentials are in contact within an aqueous environment. Generally, the effects of galvanic corrosion are precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). In galvanic couples involving brass, carbon steel, cast iron, copper, and stainless steel materials, the lower potential (more anodic) carbon steel, cast iron, and low-alloy steel would be preferentially attacked.

Crevice corrosion occurs in a wetted or buried environment when a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and non-metals, such as gasket surfaces, lap joints, and under bolt heads. Crevice corrosion is strongly dependent on the presence of dissolved oxygen. For environments with extremely low oxygen content (less than 0.1 ppm), crevice corrosion is considered insignificant. Carbon steel, cast iron, low alloy steels, stainless steel, copper, and nickel base alloys are all susceptible to crevice corrosion. However, experience at St. Lucie Units 1 and 2 shows that crevice corrosion is not a significant aging mechanism for components subjected to treated water.

Erosion is a mechanical action of fluid and/or particulate matter on a metal surface, without the influence of corrosion. Equipment exposed to moving fluids is vulnerable to erosion. These include piping, valves, vanes, impellers, etc. General erosion occurs under high velocity conditions, turbulence, and impingement. Geometric factors are extremely important. Typical forms of erosion include liquid impingement, flashing, and cavitation. Systems and components are typically designed to preclude these mechanisms. Additionally, these mechanisms are quite severe and would be discovered early in a component's life. In general, erosion mechanisms are not considered aging effects requiring management during the period of extended operation. An exception is the Unit 1 and 2 auxiliary feedwater pump recirculation lines downstream of the restriction orifices, and the Unit 2 component cooling water piping downstream from the control room air conditioners. Loss of material due to erosion has been experienced in these lines and FPL has elected to manage this effect by inspection in lieu of design modifications at St. Lucie Units 1 and 2.

Erosion/corrosion occurs when fluid or particulate is also corrosive. Erosion/corrosion is influenced by 1) fluid flow velocity, 2) geometry, 3) environmental characteristics (temperature and fluid chemistry), and 4) material susceptibility. Carbon and low alloy steels are most susceptible to erosion/corrosion. Higher alloy steels, nickel based alloys, and stainless steels are considered resistant to both erosion and erosion/corrosion. Most of the treated water systems are immune from erosion/corrosion because of their non-corrosive service fluids. One exception to the above involves high-energy piping systems that are susceptible to a form of erosion/corrosion called flow accelerated corrosion (FAC). FAC involves the dissolution of protective oxides on carbon and low alloy steel components, and continual removal of these dissolved oxides by flowing fluid. The Main Steam, Auxiliary Steam, Main Feedwater, and Steam Generator Blowdown Systems have been identified as being susceptible to FAC.

Microbiologically influenced corrosion (MIC) is a form of localized, corrosive attack accelerated by the influence of microbiological activity due to the presence of certain organisms in a wetted or buried environment. Microbiological organisms can produce corrosive substances, as a byproduct of their biological processes, that disrupt the protective oxide layer on the component materials and lead to a material depression similar to pitting corrosion. Microscopic organisms have been observed in mediums over a wide range of temperatures and pH values. However, for the purpose of aging management review, loss of material due to MIC is not considered significant at temperatures greater than 210°F or pH greater than 10.

Selective leaching (also known as dealloying) is the dissolution of one element from a solid alloy by corrosion processes in a wetted or buried environment. The most common forms of selective leaching are graphitic corrosion with the loss of the iron matrix in gray cast iron under harsh conditions, and dezincification with the removal of zinc from susceptible brass or bronze components. The addition of small amounts of alloying elements such as tin, phosphorus, arsenic, and antimony is effective in inhibiting this attack in copper-zinc alloys. Therefore, selective leaching of brass and other alloys applies only to "uninhibited" materials.

Mechanical wear is defined as damage to a solid surface by removal of parts of its material via mechanical action of a contacting solid, liquid, or gas. There are three primary types of wear: abrasive, adhesive, and erosive. Abrasive wear (scouring and gouging) is the removal of material from a surface when hard particles slide or roll across the surface under pressure. Scouring and gouging are often due to loose particles entrapped between the surfaces that are in relative motion. Adhesive wear (galling, scoring, seizing, fretting, and scuffing) involves the transference of material from one surface to another during relative motion or sliding due to a process called solid-state welding (i.e., particles that are removed from one surface are either temporarily or permanently attached to the other surfaces). Erosive wear is the mechanical wear action of a fluid and/or particulate matter on a solid surface. Erosive wear is also known as erosion, and has been discussed above.

Aggressive chemical attack is corrosion that may be localized or general, and is caused by a corrodent that is particularly active on a specified material. Boric acid is used in PWRs as a reactivity agent. The concentrations of boric acid in the Reactor Coolant Systems and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel. Most carbon steel components located inside the radiation control area were considered susceptible to boric acid corrosion. Other metals, such as copper, copper alloys, nickel, nickel alloys, and aluminum, are resistant to boric acid corrosion. [Reference C-3]

5.2 CRACKING

Cracking is non-ductile failure of a component due to stress corrosion, fatigue, or embrittlement. Cracking resulting from fatigue is typically precluded by design. However, an exception identified is the charging pump fluid blocks, which are susceptible to high cycle fatigue. The analysis of the potential for cracking due to metal fatigue is a TLAA and is addressed in Section 4.3 of this application.

SCC requires a combination of a susceptible material, a corrosive environment, and tensile stress. SCC can be categorized as either transgranular stress corrosion cracking (TGSCC) or intergranular stress corrosion cracking (IGSCC), depending on the cracking morphology. For austenitic stainless steels, TGSCC is the normal cracking mode unless the material is in a sensitized condition. As such, SCC of such materials is assumed transgranular in nature unless specified as IGSCC.

The tensile stresses necessary to induce SCC may be either applied (external) or residual (internal), but must be at or near the material's yield point. The corrosive environments that induce SCC are highly material dependent. For austenitic stainless steels and nickel-based alloys in treated water, the relevant conditions required for SCC are the presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb, and elevated temperature. For St. Lucie treated and raw water environments, a temperature criterion of greater than 140°F is utilized for susceptibility of austenitic stainless steels and nickel based alloys to SCC. However, SCC has been observed elsewhere in high purity water (i.e., halogens and sulfates less than 150 ppb and 100 ppb, respectively) at temperatures greater than 200°F with dissolved oxygen levels greater than 100 ppb. IGSCC of stainless steels is generally associated with sensitized material. Sensitization of unstabilized austenitic stainless steel is characterized by a depletion of chromium at the grain boundaries with accompanying precipitation of a network of chromium carbides occurring at elevated temperatures. Generally, an exposure period of one hour to temperatures between 800°F and 1500°F are required to fully develop the network of intergranular carbides. However, studies have shown that the thermal effects of welding followed by prolonged exposure to elevated temperatures below the normal sensitization range can also fully develop the intergranular carbide network, thereby rendering the alloys susceptible to intergranular attack (IGA) and IGSCC. Sensitization to IGSCC can occur as low as 480°F over a long period of service. Because the depletion of chromium at or near grain boundaries is caused by the formation of carbides, the carbon content of the austenitic stainless steel is critical as to the susceptibility of the material to sensitization.

For stainless steels exposed to atmospheric conditions, IGSCC is considered when the steel is exposed to high levels of contaminants (e.g., salt water) and only if the material is in a sensitized condition. Experience at St. Lucie has also revealed susceptibility to TGSCC in the non-stress relieved heat affected zone regions of weld joints of stainless steel piping located in trenches exposed to marine atmospheric conditions. The proximity of these trenches to the discharge canals on the ocean side of the plant promotes the concentration of chlorides from the salt air environment. Additionally, St. Lucie Units 1 and 2 have experienced SCC on previously heat traced piping in the Chemical and Volume Control

Systems due to external contamination. This piping is no longer heat traced, however, FPL continues to be inspected for SCC.

Apart from these exceptions, most austenitic stainless steel and nickel base alloys are resistant to SCC at temperatures less than 140°F.

NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants," NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants," and NRC IE Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Steel Piping Containing Boric Acid Solution at PWRs," describe several instances of through-wall cracking in stainless steel piping in stagnant borated water systems. NRC Bulletin 79-17 required licensees to review safety-related systems that contain stagnant, oxygenated, borated water. For these identified systems, licensees were requested to review pre-service non-destructive examinations (NDE) results, inservice NDE results, and chemistry controls. Also, ultrasonic and visual examinations of representative samples of circumferential welds were performed. The results of these reviews and inspections at St. Lucie Units 1 and 2 identified no anomalies in chemistry or indications of SCC at welds. All of the instances of SCC in the nuclear power industry have identified the presence of halogens, such as chlorides, in the failed component. These occurrences most likely resulted from the inadvertent introduction of contaminants into the system. As discussed above, SCC can occur in stainless steel at ambient temperature if exposed to a harsh enough environment (i.e., with significant contamination). However, these conditions are considered to be event-driven, resulting from the breakdown of quality controls for water chemistry and, thus, not representative of the normal environment associated with treated water.

For carbon steels, SCC occurs most commonly in the presence of aqueous chlorides. Industry data does not indicate a significant problem of SCC for low-strength carbon steels. For these reasons, SCC of carbon steels is not an aging effect requiring management.

Material fatigue resulting from vibration has been observed in the nuclear power industry and can result in crack initiation/growth. Vibration-induced fatigue is fast acting and typically detected early in a component’s life, and corrective actions are initiated to prevent recurrence. Corrective actions typically involve modifications to the plant, such as addition of supplemental restraints to a piping system, replacement of tubing with flexible hose, etc. Based upon these considerations, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.

Embrittlement is an aging mechanism that can cause cracking of rubber, neoprene, fiberglass, vinyl ester, plexiglas, plastic, or coated canvas materials at St. Lucie Units 1 and 2. Embrittlement can occur due to age, temperature, or irradiation.

5.3 FOULING

Fouling may be due to accumulation of particulates or macro-organisms (biological). Fouling is an aging effect for mechanical components that can cause loss of heat transfer intended function at St. Lucie Units 1 and 2. Additionally, macrofouling of heat exchanger tubes has resulted in the loss of material due to high localized velocities (erosion-corrosion). Biological fouling can also lead to environmental conditions conducive to MIC and crevice corrosion. Fouling evaluated for St. Lucie includes macrofouling (macro-organisms, grass, etc.), and particulate fouling due to precipitation or corrosion products. Fouling is not considered an aging effect for components with an intended function of filtration (e.g., a strainer). In these cases, the component is designed to foul, and this short-term effect is addressed by normal system operating practices.

5.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity is an aging effect associated with bolted mechanical closures that results in failure of the mechanical joint. The following potential mechanisms were evaluated for their effects on mechanical closure integrity: 1) loss of pre-load resulting from cyclic loading, gasket creep, thermal or other effects, 2) cracking of bolting material, and 3) loss of bolting material due to corrosion.

Loss of pre-load of mechanical closures can occur due to settling of mating surfaces, relaxation after cyclic loading, gasket creep, and loss of gasket compression due to differential thermal expansion. The effects of these mechanisms are the same as that of a degraded gasket; that is, the potential for external leakage of the internal fluid at the mechanical joint. Since the ASME Code does not consider gaskets, packing, seals, and O-rings to perform a pressure-retaining function, these components are typically not considered to support an intended function and are not within the scope of license renewal. Thus, the aging mechanisms associated with loss of pre-load, described above, are not considered to require management for non-Class 1 components during the period of extended operation. An exception to this would be a situation where a gasket/seal is utilized to provide a radiological boundary/barrier and thus may support an intended function. Based on the aging management review of the non-Class 1 systems at St. Lucie Units 1 and 2, there were no cases where gasket/seals are relied on to support component intended functions.

High stress in conjunction with an aggressive environment can cause cracking of certain bolting materials due to SCC. As identified in NRC IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," and NRC Generic Letter 91-17, "Generic Safety Issue 29, 'Bolting Degradation or Failure in Nuclear Power Plants,'" cracking of bolting in the industry has occurred due to SCC. These instances of SCC have been primarily attributed to the use of high yield strength bolting materials, excessive torquing of fasteners, and contaminants, such as the use of lubricants containing molybdenum disulfide (MoS_2). In response to NRC IE Bulletin 82-02, FPL verified that at St. Lucie Units 1 and 2:

- Specific maintenance procedures were in place to address bolted closures.
- The procedures in use addressed detensioning and retensioning practices and gasket installation and controls.

- Threaded fastener lubricants used in pressure boundary applications have specified maximum allowable limits for chloride and sulfur content to minimize susceptibility to SCC environments.
- Maintenance crew training on threaded fasteners is performed.

In order for SCC to occur, three conditions must exist: a susceptible material, high tensile stresses, and a corrosive environment. At St. Lucie, the potential for SCC of fasteners is minimized by utilizing ASTM A193, Gr. B7 bolting material and limiting contaminants, such as chlorides and sulfur, in lubricants and sealant compounds. Additionally, sound maintenance bolt torquing practices are used to control bolting material stresses. The use of ASTM A193, Gr. B7 bolting specifies a minimum yield strength of 105 Ksi, which is well below the 150 Ksi threshold value specified in EPRI NP-5769, "Degradation of Bolting in Nuclear Power Plants," April 1988. Bolting fabricated in accordance with this standard could be expected to have yield strengths less than 150 Ksi. However, since the maximum yield strength is not specified for this bolting material, absolute assurance cannot be provided that the yield strength of the bolting would not exceed 150 Ksi. For these cases, the combination of specifying ASTM A193 Gr. B7 bolting material, control of bolt torquing, and control of contaminants will ensure that SCC will not occur. These actions have been effective in eliminating the potential for SCC of bolting materials. The results of a review of the St. Lucie condition report (1992 through 2000) and metallurgical report (1984 through 2000) databases support this conclusion in that no instances of bolting degradation due to SCC were identified. Additionally, review of NRC generic communications did not identify any recent bolting failures attributed to SCC. Therefore, cracking of bolting material due to SCC is not considered an aging effect requiring management at St. Lucie Units 1 and 2.

Loss of bolting material, on the other hand, can result in failure of the mechanical joint and the loss of a component’s pressure boundary integrity. Therefore, the potential for this effect must be addressed. Most carbon steel bolting is in a dry environment and coated with a lubricant, thus general corrosion of bolting has not been a major concern in the industry. Additionally, stainless steel fasteners are immune to loss of material due to general corrosion. Corrosion of fasteners has only been a concern where leakage of a joint occurs, specifically, when bolting is exposed to aggressive chemical attack such as that resulting from borated water leaks.

Aggressive chemical attack is corrosion that may be localized or general, and is caused by a corrodent that is particularly active on a specified material. Boric acid is used in PWRs as a reactivity agent. The concentrations in the Reactor Coolant System and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel. Loss of mechanical closure integrity due to boric acid corrosion was considered as a potential aging effect for components in proximity to borated water systems.

5.5 REDUCTION IN FRACTURE TOUGHNESS

Thermal embrittlement is a mechanism by which the mechanical property fracture toughness is affected as a result of exposure to elevated temperature. CASS materials are susceptible to thermal embrittlement dependent upon material composition and the time at temperature. CASS materials subjected to temperatures >482°F are considered susceptible. Low alloy steels may be subject to embrittlement from exposure to temperatures in the range of 570°F - 1100°F. The loss of fracture toughness may not be accompanied by significant changes in other material properties.

Neutron embrittlement is the loss of fracture toughness resulting from the bombardment of neutrons. The loss of fracture toughness may be accompanied by detectable increases in material hardness. The overall effects of neutron embrittlement on steel are to increase yield strength, decrease the ultimate tensile ductility, and increase the ductile to brittle transition temperature. Neutron embrittlement is considered a potential aging mechanism requiring management only inside the reactor cavity.

5.6 DISTORTION/PLASTIC DEFORMATION

Creep is defined as time-dependent strain, or gradual elastic and plastic deformation, of metal that is under constant stress at a value lower than its normal yield strength. Creep is a concern when the component operating temperature approaches or exceeds the recrystallization temperature for the metal. Austenitic stainless steel with temperatures <800°F, and carbon steel and low alloy steels with temperatures <700°F are not susceptible to creep. All St. Lucie Nuclear Plant systems operate <700°F and, thus, are not susceptible to creep.

Stress relaxation is the time-dependent decrease in stress in a solid under constant constraint at constant temperature. The rate of stress relaxation is temperature dependent. As a rule, stress relaxation is not a significant problem at temperatures less than one-half of the melting point. All St. Lucie Nuclear Plant systems operate below the temperature at which stress relaxation occurs and, thus, are not susceptible to stress relaxation.

6.0 REFERENCES

C-1 C. I. Grimes (NRC) letter to D. J. Walters (NEI), "License Renewal Issue No. 98-0013, Degradation Induced Human Activities," June 5, 1998.

C-2 NEI 95-10, Revision 3, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Nuclear Energy Institute, January 2000.

C-3 "Handbook of Corrosion Data", American Society of Metals, 1995.

APPENDIX D

TECHNICAL SPECIFICATION CHANGES

TECHNICAL SPECIFICATION CHANGES

The Code of Federal Regulations, Title 10, at 54.22, requires applicants to include any Technical Specification changes, or additions, necessary to manage the effects of aging during the period of extended operation as part of the renewal application. Based on a review of the information provided in the St. Lucie Units 1 and 2 license renewal application and Technical Specifications, no license amendment requests for St. Lucie Units 1 and 2 Technical Specifications are being submitted with this application.