3. AGING MANAGEMENT REVIEW RESULTS

3.0 Aging Management Programs

3.0.1 Introduction

This section of the Safety Evaluation Report (SER) contains the staff's evaluation of the aging management programs (AMPs) that are referenced in the aging management review (AMR) for two or more systems and/or structures and therefore are considered common AMPs. The remaining programs are system-specific and will be evaluated at the beginning of subsequent sections of this SER. It should be noted that the staff's conclusions on the evaluations of these system-specific AMPs may be predicated on the assumption that the AMPs are implemented in conjunction with other AMPs (if more than one AMP is credited by the applicant) as discussed in subsequent sections of this SER.

The applicant claimed that 11 of the AMPs are consistent with the programs described in the Generic Aging Lessons Learned (GALL) report. The description of the staff's review of these AMPs, which are consistent with the GALL Report, is contained in Section 3.0.2 of this SER. The description of the staff's review of the AMPs that are not consistent with the GALL Report is contained in Section 3.0.3 of this SER. The description of the staff's review of Florida Power and Light Company's (FPL's) Quality Assurance Program is contained in Section 3.0.4 of this SER. The common AMPs are evaluated in Section 3.0.5 of this SER.

Table 3.0.1-1 of this SER presents the common AMPs, the associated GALL Report program if applicable, the system groups that credit the program for management of component aging, and the SER section that contains the staff's review of the program.

Table 3.0.1-1 Common Aging Management Programs

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Galvanic Corrosion Susceptibility Inspection Program (B.3.1.2)	None	3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion	3.0.5.1
Pipe Wall Thinning Inspection Program (B.3.1.3)	None	3.3–Auxiliary 3.4–Steam and Power Conversion	3.0.5.2
ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B.3.2.2.1)	XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC and IWD"	3.1–RCS 3.2–ESF	3.0.5.3

APPLICANT’S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Boric Acid Wastage Surveillance Program (B.3.2.4)	XI.M10, “Boric Acid Corrosion”	3.1–RCS 3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion 35–Structures	3.0.5.4
Chemistry Control Program - Water Chemistry Control Subprogram (B.3.2.5.1)	XI.M2, “Water Chemistry”	3.1–RCS 3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion 3.5–Structures	3.0.5.5
Chemistry Control Program - Closed-Cycle Cooling Water System Chemistry Subprogram (B.3.2.5.2)	XI.M21, “Closed-Cycle Cooling Water System”	3.1–RCS 3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion 3.5–Structures	3.0.5.6
Fire Protection Program (B.3.2.8)	None	3.3–Auxiliary 3.5–Structures	3.0.5.7
Flow-Accelerated Corrosion Program (B.3.2.9)	XI.M17, “Flow-Accelerated Corrosion”	3.1–RCS 3.4–Steam and Power Conversion	3.0.5.8
Periodic Surveillance and Preventive Maintenance Programs (B.3.2.11)	None	3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion 3.5–Structures	3.0.5.9
Systems and Structures Monitoring Program (B.3.2.14)	None	3.2–ESF 3.3–Auxiliary 3.4–Steam and Power Conversion 3.5–Structures	3.0.5.10

Table 3.0.1-2 of this SER presents the system-specific aging management programs, the associated GALL Report program if applicable, the system group that credits the program for management of component aging, and the SER section that contains the staff’s review of the program.

Table 3.0.1-2 System-Specific Management Programs

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Condensate Storage Tank Cross-Connect Buried Piping inspection (Unit 1 only) (B.3.1.1)	None	3.4–Steam and Power Conversion	3.4.0.1
Reactor Vessel Internals Inspection Program (B.3.1.4)	None	3.1–RCS	3.1.0.7
Small Bore Class 1 Piping Inspection (B.3.1.5)	None	3.1–RCS	3.1.0.3
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.3.1.6)	XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	3.1–RCS	3.1.0.2
Alloy 600 Inspection Program (B.3.2.1)	None	3.1–RCS	3.1.0.1
ASME Section XI, Subsection IWE Inservice Inspection Program (B.3.2.2.2)	XI.S1, "ASME Section XI, Subsection IWE" XI.S4, "10 CFR 50, Appendix J"	3.5–Structures	3.5.0.1
ASME Section XI, Subsection IWF Inservice Inspection Program (B.3.2.2.3)	XI.S2, "ASME Section XI, Subsection IWF"	3.5–Structures	3.5.0.2
Boraflex Surveillance Program (Unit 1 only) (B.3.2.3)	XI.M22, "Boraflex Monitoring"	3.5–Structures	3.5.0.3
Chemistry Control Program - Fuel Oil Chemistry Subprogram (B.3.2.5.3)	None	3.3–Auxiliary	3.3.0.1
Environmental Qualification Program (B.3.2.6)	X.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.6–Electrical	TLAA 4.4
Fatigue Monitoring Program (B.3.2.7)	None	3.1–RCS	3.1.0.6

APPLICANT'S AMP (LRA SECTION)	ASSOCIATED GALL PROGRAM	SYSTEM GROUPS	STAFF EVALUATION (SER SEC.)
Intake Cooling Water System Inspection Program (B.3.2.10)	None	3.3–Auxiliary	3.3.0.2
Reactor Vessel Integrity Program (B.3.2.12)	None	3.1–RCS	3.1.0.5
Steam Generator Integrity Program (B.3.2.13)	XI.M19, "Steam Generator Tube Integrity"	3.1–RCS	3.1.0.4
Non-EQ Cable and Connection Aging Management Program (Response to RAI 3.6 -1; letter dated 9/26/02)	None	3.6–Electrical	3.6.0.1

3.0.2 Aging Management Programs Consistent with GALL

3.0.2.1 The GALL Evaluation Process

Following the general format of NUREG-0800, "Standard Review Plan for Review of the License Renewal Applications for Nuclear Power Plants," the staff reviewed the aging effects on components and structures, identified the relevant existing programs, and evaluated program elements to manage aging effects for license renewal. The staff's evaluation of the adequacy of each generic aging management program in managing certain aging effects for particular structures and components is based on the review of 10 program elements;

1. program scope
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. corrective actions
8. confirmation process
9. administrative controls
10. operating experience

These elements are described in Appendix A of NUREG-1800 and in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report."

The staff documented acceptable generic AMPs, such as the ASME Section XI Inservice Inspection, Water Chemistry, and Structures Monitoring Programs in Chapter XI of the GALL Report. If the material presented in the GALL Report is applicable to the applicant's facility, the staff will find the applicant's response acceptable. In making this determination, the staff will consider whether the applicant has identified specific programs described and evaluated in the GALL Report. The staff, however, will not conduct a re-review of the substance of the matters described in the GALL Report. Rather, the staff will ensure the applicant verifies that the approvals set forth in the GALL Report for generic programs apply to the applicant's programs.

The focus of the staff's review is on augmented programs for license renewal. For the AMPs that are not consistent with the GALL Report, the reviewer will evaluate the 10 elements described in the GALL report. The staff's review of these AMPs is described in Section 3.0.3 of this SER.

If an applicant takes credit for an AMP being consistent with the GALL Report, it is incumbent on the applicant to ensure that the plant program contains all the elements of the referenced GALL program. In addition, the conditions at the plant must be bounded by the conditions for which the GALL program was evaluated. The above verifications must be documented on site in an auditable form. The applicant must include a certification in the renewal application that the verifications have been completed and are documented on site in an auditable form. The staff will confirm that these AMPs are consistent with the GALL Report during on site inspections and will document its findings in an inspection report.

In order to determine if evaluating AMRs and AMPs for consistency with the GALL Report would improve the efficiency of the license renewal review, the staff and industry conducted a demonstration project to exercise the GALL process and determine the format and content of a safety evaluation based on the GALL review process. NUREG-1800, the Standard Review Plan, was prepared based on both the GALL model and the lessons learned from the demonstration project. On the basis of the lessons learned from the demonstration project, the staff determined that if an applicant commits to implementing the staff-approved AMPs identified in the GALL Report, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process.

3.0.2.2 The Staff's Review Process for Programs Consistent with the GALL Report

Florida Power and Light Company is the first license renewal applicant to utilize the GALL Report for evaluating its AMPs. The staff's review of the St. Lucie Units 1 and 2 AMPs was performed in three phases. In Phase 1, the staff reviewed the AMPs that the applicant claimed were consistent with the GALL Report. The staff compared these AMPs to the associated AMPs described in Section XI of the GALL Report. The AMPs will be discussed further in the sections of this SER identified in Table 3.0.1 above. For the AMPs for which the GALL Report recommended further evaluation, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report.

For those AMPs that are not consistent with the GALL Report, the staff evaluated the AMPs against the 10 program elements described in the GALL Report. The staff's review of these AMPs is described in Section 3.0.3 of this SER. The staff also reviewed the final safety analysis report (FSAR) supplements in Appendix A of the LRA for each AMP to determine whether it provided an adequate description of the program or activity, as required by 10 CFR 54.21(d).

In Phase 2, the staff determined whether the applicant's AMRs and associated AMPs were adequate to manage the aging effects for which they were credited. In Phase 3, the staff reviewed plant-specific structures and components to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an on-site aging management review (AMR) inspection to confirm the applicant's claim that specific aging management programs (AMPs) were consistent with the AMPs in the Generic Aging Lessons Learned (GALL) Report. Even though, the staff's AMR inspection will be completed when this SER is issued, the inspection report will not. When the inspection report is issued, the staff will confirm there are no open items related to license renewal and that the inspectors confirmed the applicant's claim that specific AMPS are consistent with the GALL Report. This is Open Item 3.0.2.2-1.

3.0.3 Aging Management Programs Not Consistent with the GALL Report

The staff's evaluation of the applicant's AMPs that are not consistent with the GALL Report focuses on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff used 10 elements to evaluate each program and activity. The 10 elements of an effective AMP were developed as part of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," which was issued in July 2001. This SER describes the extent to which the 10 elements are applicable to a particular program or activity, and evaluates each program and activity against those elements that are determined to be applicable. On the basis of NRC experience with maintenance programs and activities the staff concluded that conformance with the 10 elements of an AMP, or a combination of AMPs, provides reasonable assurance that an AMP (or combination of programs and activities) is demonstrably effective at managing an applicable aging effect. The 10 elements of an effective AMP will be considered in evaluating each AMP used by the applicant to manage the applicable aging effects identified within this SER.

In the LRA, Appendix B, Section 2.2, "Attribute Definitions," the applicant described the elements involving corrective actions and confirmation processes for license renewal. The staff's evaluation of the applicant's quality assurance attributes associated with the AMPs credited for license renewal is discussed below.

3.0.4 FPL Quality Assurance Program Attributes Integral to Aging Management Programs

The NRC staff has reviewed LRA Appendix B Section 2.0, "Aging Management Program Attributes," in accordance with the requirements of 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes, namely corrective actions, confirmation process, and administrative controls. These three attributes of the quality assurance program are addressed for all of the applicant's AMPs.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components that are subject to an AMR will be adequately managed to ensure that their intended functions will be maintained in a manner that is consistent with the CLB of the facility throughout the period of extended operation. To manage these effects, applicants have developed new or revised existing AMPs and applied those programs to the SSCs of interest. For each of these AMPs, the existing 10 CFR Part 50, Appendix B, quality assurance program may be used to address the attributes of corrective actions, confirmation process, and administrative controls.

3.0.4.1 Summary of Technical Information in Application

Chapter 3.0, "Aging Management Review Results," of the LRA provides an AMR summary for each unique structure, component, or commodity group at St Lucie determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management and AMPs utilized to manage these aging effects. Appendix B to the LRA demonstrates how the identified programs manage aging effects using attributes consistent with the industry and NRC guidance. Specifically, the applicant uses the following specific attributes to describe these programs and activities:

1. Corrective Actions - This attribute is a description of the action taken when the established acceptance criterion or standard is not met. This includes timely root-cause determination and prevention of recurrence, as appropriate

2. Administrative Controls - This attribute is an identification of the plant administrative structure under which the programs are executed.

3. Scope - This attribute is a clear statement of the reason why the program exists for license renewal.

4. Preventive Actions - This attribute is a description of preventive actions taken to mitigate the effects of the susceptible aging mechanisms and of the basis for the effectiveness of these actions.

5. Parameters Monitored or Inspected - This attribute is a description of parameters monitored or inspected, and how they relate to the degradation of the particular component or structure, and its intended function.

6. Detection of Aging Effects - This attribute is a description of the type of action or technique used to identify or manage the aging effects or relevant conditions.

7. Monitoring and Trending - This attribute is a description of the monitoring, inspection, or testing frequency, and sample size (if applicable).

8. Acceptance Criteria - This attribute is an identification of the acceptance criteria or standards for the relevant conditions to be monitored or the chosen examination methods.

9. Confirmation Process - This attribute is a description of the process to ensure that adequate corrective actions have been completed and are effective.

10. Operating Experience and Demonstration - This attribute is a summary of the operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs.

In Section 2.0 of Appendix B to the LRA, the applicant provides a generic description of the corrective actions and administrative controls common to all AMPs credited for license renewal. In this section, the applicant states that the corrective actions and administrative controls apply to all AMPs that are credited for license renewal. The confirmation process description for each AMP is incorporated directly into each AMP. Those descriptions contain a statement about the confirming processes for each AMP which include follow-up inspections, tests, or examinations, if required, based upon actual programmatic criteria, such as corrosion rates, material conditions or prior inspection or examination findings. Those confirming processes are documented in accordance with the corrective action program. The corrective actions and administrative controls are described as part of the applicant's quality assurance program required by 10 CFR Part 50, Appendix B. For each aging management program listed in Section 3.0, "Aging Management Programs," of Appendix B to the LRA, the confirmation process is described as establishing follow-up examination or inspection requirements based on the evaluation of the inspection results. Also, the applicant states that it will specify unacceptable evaluation results in its corrective action program.

Additionally, the applicant noted that the FPL corrective action program is an existing and effective program for identifying, evaluating, and correcting deficiencies and is implemented in accordance with the Quality Assurance Program. Under the guidance of the FPL Quality Assurance Program, Quality Instructions and Administrative Procedures for corrective actions require that any deficiency documented by an individual 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.

3.0.4.2 Staff Evaluation

The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes, namely corrective actions, confirmation process, and administrative controls. These three attributes of the quality assurance program are used by all of the applicant's AMPs.

During the audit of the St Lucie scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated UFSAR Supplement," and Appendix B, "Aging Management Programs," to assure that the aging management activities were consistent with the staff's guidance described in section A.2, "Quality Assurance for Aging Management Programs" and Branch Technical Position IQMB-1, regarding quality assurance (QA) of the LR-SRP. During the review, the applicant stated that the attributes of corrective action, confirmation process, and administrative control were developed and are integral to the site quality assurance programs. The audit team confirmed that the applicant credited this process for both the safety-related and non safety-related SSCs within the scope of license renewal. In addition, the team verified that the definitions for each of the attributes of the AMPs was consistent with those definitions in Section A.2 of the SRP for Review of License Renewal Applications.

Based on the staff's evaluation, the description and applicability of the AMPs and their associated attributes to all safety-related and non safety-related SCs provided in Appendix B of the LRA is consistent with the staff's position regarding quality assurance for aging management. However, the staff noted that the applicant had not sufficiently described the use of the quality assurance program and its associated attributes in the FSAR supplements discussion provided in Appendix A of the LRA. In a letter dated July 1, 2002, the staff requested that the applicant revise their description in Appendix A, Chapter 18.0, "Updated UFSAR Supplement," of the LRA to include aspects of the quality assurance program consistent with the description provided in Appendix B of the LRA (RAI 2.1-3).

In a letter dated September 26, 2002 (FPL Letter No. L-2002-139), the applicant provided a response to the staff's request for additional information. In that response, the applicant further described the quality assurance program and provided a revised introductory description for the FSAR supplements. Specifically, the applicant stated that the FPL corrective action program is an existing and effective program for identifying, evaluating, and correcting deficiencies and is implemented in accordance with FPL's 10 CFR 50 Appendix B Quality Assurance Program. Under the guidance of the FPL Quality Assurance Program, Quality Instructions and Administrative Procedures for corrective actions require that any deficiency documented by an individual 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. Accordingly, the confirmation process is part of the corrective action program and the FPL Quality Assurance Program.   Additionally, deficiencies identified during the performance of inspections or activities associated with any of the aging management programs or time-limited aging analyses will be entered into the appropriate corrective action program and actions including confirmation activities will be performed accordingly.

In their response to the staff's RAI, the applicant has committed to revise the St. Lucie Unit 1 and 2 FSAR supplements (LRA Appendices A1 and A2) to state, in part, that:

> FPL has established and implemented a Quality Assurance Program to provide assurance that the design, procurement, modification and operation of nuclear power plants conform to applicable regulatory requirements. The FPL Quality Assurance Program, described in the FPL Topical Quality Assurance Report, is in compliance with the requirements of 10 CFR 50, Appendix B. For all aging management programs credited for license renewal, the program attributes of Corrective Actions, Confirmation, and Administrative Controls are performed or, in the case of new programs will be performed, in accordance with the FPL Quality Assurance Program, and will apply to all components and structural components within the scope of the programs, including non safety-related components and structural components.

On the basis of the information provided in the LRA, as supplemented by the applicant's response to the staff's RAI dated July 1, 2002, the NRC staff has determined that for all AMPs credited for license renewal, the corrective actions, confirmation process, and administrative controls are addressed in the applicant's approved quality assurance program. The staff finds that the FPL Topical Quality Assurance Report contains the applicant's commitments for managerial and administrative controls, including a discussion of how the applicable requirements of Appendix B to 10 CFR Part 50 will be satisfied. Therefore, RAI 2.1-3 is considered resolved.

3.0.4.3 Conclusion

The staff finds that the quality assurance attributes are consistent with 10 CFR 54.21(a)(3). The staff finds that the applicant's descriptions, in Chapter 18 of the FSAR supplements, as revised in its response dated September 26, 2002, to the staff's RAI 2.1-3 provides a sufficient description of the quality assurance program attributes and activities for managing the effects of aging. Therefore, the applicant's quality assurance attributes within the AMPs credited for license renewal are acceptable.

3.0.5 Common Aging Management Programs

3.0.5.1 Galvanic Corrosion Susceptibility Inspection Program

The Galvanic Corrosion Susceptibility Inspection Program is described in Section 3.1.2 of Appendix B to the LRA. This program provides aging management of component/commodity groups of several systems (listed in Section 3.0.5.1.1 of this SER) for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Galvanic Corrosion Susceptibility Inspection Program will adequately manage the aging effects for components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.1.1 Summary of Technical Information in the Application

In Section 3.1.2 of Appendix B of the LRA, the applicant describes a new program that characterizes loss of material due to galvanic corrosion caused by exposure to gas, unmonitored treated water, and raw water environments. The applicant's Galvanic Corrosion Susceptibility Inspection Program is credited with the aging management of specific component/commodity groups in the following systems:

- auxiliary feedwater and condensate
- component cooling water
- containment cooling
- containment spray
- diesel generator and support systems
- fire protection
- fuel pool cooling
- instrument air
- main feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine
- primary makeup water
- safety injection
- turbine cooling water (Unit 1 only)
- ventilation

The applicant's program is credited for managing the potential loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. Loss of material is expected mainly in carbon steel components directly coupled to stainless steel components in raw water systems; however, the applicant stated that baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The program involves one-time inspections whose results will be utilized to determine the need for additional programs and will be implemented prior to the end of the initial operating license term for St. Lucie.

The applicant's Galvanic Corrosion Susceptibility Inspection Program is a new program that will use techniques with demonstrated capability and a proven industry record to monitor material loss due to galvanic corrosion. The applicant's examinations will be performed utilizing approved plant procedures and qualified personnel. The inspection techniques that will be used in this program have been used previously to monitor material condition for plant systems. This program will quantify the significance of this potential aging effect. This is a one-time inspection, and the locations selected for inspection will represent those with the greatest susceptibility to galvanic corrosion. Initial inspection results will be used to assess the need for expanded sample locations. The applicant provided additional information about this program in its letter dated September 26, 2002, in response to RAI B.3.1.2-1.

3.0.5.1.2 Staff Evaluation

The staff reviewed the information in Section 3.1.2 of Appendix B of the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions in the FSAR supplements of the Galvanic Corrosion Susceptibility Inspection Program in Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 of the LRA. The staff's evaluation of the applicant's Galvanic Corrosion Susceptibility Inspection Program focused on how the program manages aging effects through the effective incorporation of 10 elements—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled Quality Assurance Program. The staff's evaluation of the Quality Assurance Program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: This program is credited for managing the potential loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The applicant expects loss of material mainly in carbon steel components directly coupled to stainless steel components in raw water systems. Baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The applicant noted that this program involves one-time inspections, the results of which will be utilized to determine the need for additional programmatic actions.

The applicant further stated that since the inspection of all locations with the potential for galvanic corrosion is not practical, an engineering specification will be developed to provide the methodology for identifying those galvanic couples where corrosion is most likely to occur and where inspection results can be used to bound less susceptible locations. Selection of locations with greatest susceptibility to galvanic corrosion is based on (1) how far apart the two dissimilar metals are on the galvanic series chart, (2) the conductivity of the electrolyte, and (3) the relative size of the anode and cathode.

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

Preventive Actions: The applicant noted some components and systems utilize insulating flanges or cathodic protection as preventive measures to minimize galvanic interaction. Furthermore, the applicant noted that the use of insulating flanges and cathodic protection performs a preventive function but is not credited for elimination of galvanic corrosion. The staff determined that the purpose of the program is to visually examine those areas within the scope of the program and take corrective action where required. Therefore, preventive or mitigative actions are not required.

Parameters Monitored or Inspected: Techniques such as ultrasonic examinations to measure thickness of the components for material loss and visual examinations to examine the condition of the component for discoloration, overall condition, and other signs of corrosion will be performed on the susceptible components. These examination methods are consistent with current industry practice and are capable of identifying thinning of the selected components and are thus acceptable. Therefore, the staff finds the applicant's parameters monitored and inspection methods acceptable.

Monitoring and Trending: Since this is a one-time inspection, there are no monitoring and trending aspects to this program. The staff finds this acceptable.

Detection of Aging Effects: As discussed above, the staff finds the inspection program scope and technique to be applied to be acceptable. With respect to inspection timing, the applicant did not provide the staff with a schedule other than to state the Galvanic Corrosion Susceptibility Inspection Program will be implemented prior to the expiration of the initial operating license term for St. Lucie (that is the 40th year of operation). The staff did not identify the need for a specific commitment from the applicant to perform a galvanic susceptibility inspection at a particular time. Thus, recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the LRA, the staff accepts the applicant's general commitment to complete the Galvanic Corrosion Susceptibility Inspection Program before the end of the 40th year of operation because the staff expects minimal progression for aging effects due to the robust design and relatively benign operating conditions. In conclusion, the staff finds that the inspection scope, technique, and schedule support the applicant's intention of confirming this corrosion mechanism need not be managed for the period of extended operation.

Acceptance Criteria: The applicant's program consists of a confirmatory one-time inspection of piping to verify that loss of material due to galvanic corrosion is not occurring. Furthermore, the applicant noted that in the event that significant loss of material is detected during the inspection, appropriate corrective actions will be taken in accordance with the corrective action program. The applicant indicated that evaluation of the inspection results will consider the measured wall thickness, calculated corrosion rate, and projected wall thickness and will ensure the minimum required wall thickness is maintained pursuant to the applicable code requirements. The staff finds the applicant's acceptance criteria reasonable and therefore acceptable.

Operating Experience: The Galvanic Corrosion Susceptibility Inspection Program was developed to quantify the significance of loss of material due to this corrosion mechanism and provide for managing the effects of aging, if required. This program constitutes a one-time inspection of selected locations in treated water and other systems which have been identified as potentially susceptible to galvanic corrosion. The other systems have internal environments of condensed atmosphere in portions of instrument air and ventilation and raw water—city water in fire protection system. The applicant further stated that a review of the plant-specific operating experience for these other systems (i.e., the instrument air and ventilation system and the fire protection system) also did not identify significant galvanic corrosion. Therefore, they are included in the program for one-time inspection.

Although the applicant stated that significant galvanic corrosion has not been experienced and is not anticipated in treated water systems due to the high purity of the water and its low conductivity, the applicant had instances of galvanic corrosion at St. Lucie, primarily in the intake cooling water system. Galvanic corrosion for the intake cooling water 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. The staff concludes that the applicant's operating experience supports its proposed one-time galvanic corrosion inspection program.

3.0.5.1.3 FSAR Supplement

Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 of the LRA provide the applicant's FSAR supplements for the Galvanic Corrosion Susceptibility Inspection Program. The program descriptions are consistent with the material contained in Section 3.1.2 of Appendix B of the LRA, with the exception in the areas of acceptance criteria and inspection technique. Prior to issuance of new licenses, the applicant needs to revise the FSAR supplements to describe these two attributes consistent with the SER. This is confirmatory item 3.0.5.1-1.

3.0.5.1.4 Conclusions

The staff finds that the applicant has demonstrated that the effects of aging associated with the structures and components of the Galvanic Corrosion Susceptibility Inspection Program will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory item 3.0.5.1-1, the staff also concludes that the FSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.5.2 Pipe Wall Thinning Inspection Program

The applicant described its Pipe Wall Thinning Inspection Program in Section 3.1.3 of Appendix B of the LRA. The applicant credits this program with managing the aging of specific components in the Units 1 and 2 auxiliary feedwater and condensate system and in the Unit 2 component cooling water system. The staff reviewed Section 3.1.3 of Appendix B of the LRA to determine whether the applicant has demonstrated that the Pipe Wall Thinning Inspection Program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.2.1 Summary of Technical Information in the Application

The Pipe Wall Thinning Inspection Program is a new program credited for aging management of specific component/commodity groups in the auxiliary feedwater and condensate system in Units 1 and 2 and the component cooling water system in Unit 2. The program is plant specific. There is no comparable aging management program in the GALL Report.

The program provides for volumetric examination methods to detect loss of material by measuring wall thickness resulting from pipe wall erosion. It involves periodic inservice volumetric inspections and specifies minimum wall thickness acceptance criteria based on American National Standards Institute (ANSI) B31.7 and ASME Section III.

3.0.5.2.2 Staff Evaluation

The staff has reviewed the information provided in Section 3.1.3 of Appendix B of the LRA, the summary description of the Pipe Wall Thinning Inspection Program in Appendix A of the LRA, and the applicant's September 26, 2002, response to the staff's RAIs. The staff's evaluation of the Pipe Wall Thinning Inspection Program focused on how the applicant demonstrates that the applicable aging effects of the structures and components that credit this program will be managed during the period of extended operation. The staff evaluated the program against 10 elements that are described in Appendix A to NUREG-1800—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the inspections involves examination of auxiliary feedwater and condensate system stainless steel piping components downstream of the auxiliary feedwater recirculation orifices and carbon steel components in Unit 2 component cooling water return piping. The staff considers the scope of this program acceptable because it covers the components that are susceptible to wall thinning.

Preventive Actions: The applicant stated that no preventive actions are applicable to this inspection, and the staff did not identify a need for any preventive or mitigating actions.

Parameters Monitored or Inspected: The program will assess the extent of localized wall thinning due to erosion of the internal surfaces of the monitored piping by the periodic measurement of the wall thickness at the selected locations of the affected piping systems. The staff finds that measuring the wall thickness provides an acceptable method to assess the extent of the wall thinning.

Detection of Aging Effects: The applicant stated that the detection of loss of material will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing or radiography. The staff finds that these techniques effectively measure wall thickness and are acceptable.

Monitoring and Trending: The applicant stated that the frequency of inspections will be established based on the initial inspection results, considering the measured wall thickness, corrosion rates, and minimum required wall thickness. The need for any replacements or change in inspection frequency will be determined based on the results of each inspection.

In RAI B.3.1.3-3, the staff requested that the applicant provide an explanation of the apparent inconsistency between the terms “erosion rates” and “corrosion rates.” In addition, the staff requested an explanation of how those rates are determined. By letter dated September 26, 2002, the applicant responded by stating that the apparent inconsistency between the terms “erosion rates” and “corrosion rates” was the result of a typographical error. The text in the Monitoring and Trending portion should therefore read, “The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, erosion rates, and minimum required wall thickness.”

The applicant also described the method used to determine the pipe wall erosion rates. The Pipe Wall Thinning Inspection Program provides for volumetric examination methods to detect loss of material by measuring component wall thickness. This measured wall loss is divided by the time the component has been in service (hours, years, etc.) to determine a conservative erosion rate. The applicant stated that this method has been used at St. Lucie in the past and has proven to be an effective method for the determination of erosion rates. The staff finds the applicant’s response acceptable and considers the method used by the applicant for determining the pipe wall erosion rates reasonable and acceptable.

Acceptance Criteria: The applicant stated that the evaluation of the inspection results will consider the minimum required wall thickness in accordance with ANSI B31.7 for Unit 1 auxiliary feedwater piping and ASME Section III for Unit 2 auxiliary feedwater piping and component cooling water piping.

In RAI B.3.1.3-1, the staff requested that the applicant provide the specific section of ANSI B31.7 that will be the basis for calculating the required minimum wall thickness for Unit 1 auxiliary feedwater piping. By letter dated September 26, 2002, the applicant stated that, as indicated in Table 3.9-4 of the St. Lucie Unit 1 UFSAR, the auxiliary feedwater piping is designed in accordance with ANSI B31.7, “Nuclear Power Piping,” Code Classes 2 and 3. The particular portion of auxiliary feedwater piping within the scope of the Pipe Wall Thinning Inspection Program is designed to ANSI B31.7 Code Class 3 requirements. Accordingly, Chapter 3-II, Part 2, “Pressure Design of Piping Components,” of ANSI B31.7 will be used as a basis for calculating the required minimum wall thickness for the subject piping. The staff determined that Chap 3-II, Part 2, of ANSI B31.7 requires the same provisions for calculating the required minimum wall thickness as USAS B31.1.0, which has been approved by the staff.

In RAI B.3.1.3-2, the staff requested that the applicant provide the specific section in ASME Code, Section III, that will be the basis for calculating the required minimum wall thickness for the Unit 2 auxiliary feedwater piping and component cooling water piping. By letter dated September 26, 2002, the applicant stated that, as indicated in Table 9.2-4 of the St. Lucie Unit 2 UFSAR, the component cooling water piping is designed in accordance with ASME Section III, Class 3 requirements. Similarly, Table 10.4-1 of the St. Lucie Unit 2 UFSAR identifies the design code for auxiliary feedwater piping as ASME Section III, Class 2/3. The particular portion of the St. Lucie Unit 2 auxiliary feedwater piping within the scope of the Pipe Wall Thinning Inspection Program is designed to ASME Section III, Class 3 requirements. Accordingly, ND-3600, "Piping Design," of ASME Section III will be used as a basis for calculating the required minimum wall thickness for the subject piping. The staff finds that using ASME Section III, ND-3600, as a basis for calculating the required minimum wall thicknesses is acceptable because it meets the requirements of 10 CFR 50.55a(a)(2).

Operating Experience: The applicant stated that St. Lucie Units 1 and 2 have experienced pipe wall thinning due to erosion in the auxiliary feedwater recirculation lines and the Unit 2 control room air conditioning component cooling water return lines. In lieu of design modifications to address high-fluid velocity conditions in these locations, the applicant elected to periodically inspect the susceptible lines to manage loss of material. Volumetric inspection techniques have been used to monitor these lines. The examinations will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been used previously to assess this piping condition in many other plant systems. The staff notes that operating experience identified the need for this program, and the subsequent volumetric inspections have been used to monitor susceptible lines. The staff concludes that the applicant adequately considered operating experience when it developed this new AMP.

3.0.5.2.3 FSAR Supplement

The staff reviewed the FSAR supplements in Appendix A of the LRA. The staff finds that the FSAR supplements for Units 1 and 2 contain an adequate summary description of the program activities associated with the Pipe Wall Thinning Inspection Program for managing the effects of aging, as required by 10 CFR 54.21(d).

3.0.5.2.4 Conclusions

The staff finds that the Pipe Wall Thinning Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended function will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.5.3 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is described in Section 3.2.2.1 of Appendix B to the LRA. This program provides aging management of the reactor coolant system and containment spray component/commodity groups for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.3.1 Summary of Technical Information in the Application

In Section 3.2.2.1 of Appendix B to the LRA, the applicant identifies that aging management of specific reactor coolant system and containment spray component/commodity groups will be managed by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The applicant states that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with the 10 program elements of AMP XI.M1, “ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD,” as specified in NUREG-1801, Volume 2, “Generic Aging Lessons Learned (GALL) Report, Tabulation of Results,” dated July 2001. To address aging issues of surge lines, core stabilizing lugs, and core support lugs that were identified by the staff during its review of the Turkey Point LRA, the applicant indicated that the subject program would be enhanced. The enhancements will require evaluation of surge-line flaws (if identified) with regard to environmentally assisted fatigue and will require VT-1 visual inspections of the core stabilizing lugs and core support lugs. The commitment dates associated with enhancements to this program are contained in Appendix A of the LRA.

3.0.5.3.2 Staff Evaluation

The staff reviewed the information in Section 3.2.2.1 of Appendix B of the LRA and the summary descriptions of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program in the FSAR supplement Section 18.2.2.1 of Appendices A1 and A2 of the LRA. The 10 program elements in the GALL Report AMP XI.M1, “ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD,” provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects identified for specific component/commodity groups in the reactor coolant and containment spray systems. In Appendix B, Section 3.2.2.1, of the LRA, the applicant stated that the program elements for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program are consistent with those specified in GALL AMP XI.M1. In addition, the enhancements, discussed above, are consistent with what the staff has accepted for previous applications and are adequate to detect aging effects of the surge line and core stabilizing and support lugs. The applicant retains the description of the subject program, as well as the descriptions for the program’s 10 elements, on record at the St. Lucie Nuclear Station.

The staff inspected the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for acceptability and compared the program’s 10 elements to the 10 elements described in GALL AMP XI.M1. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff's review of the inspection findings is Open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the FSAR Supplements' descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1

3.0.5.3.3 FSAR Supplement

Section 18.2.2.1 of Appendices A1 and A2 of the LRA provide the applicant's FSAR supplements for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Programs. The staff reviewed the section to verify that the information in the FSAR supplements provides an adequate summary of the program activities required by 10 CFR 54.21(d). With the exception of confirmatory item 3.0.2.2-1, the staff finds the FSAR supplements sufficient.

3.0.5.3.4 Conclusions

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.0.5.4 Boric Acid Wastage Surveillance Program

The applicant described its Boric Acid Wastage Surveillance Program in Section 3.2.4 of Appendix B of the LRA. The applicant states that the program is consistent with the 10 attributes of AMP XI.M10, "Boric Acid Corrosion," specified in the GALL report [NUREG-1800). In addition, St. Lucie credits this program for monitoring borated water systems for leakage that could
potentially affect systems and components credited with a license renewal function, whereas the GALL program is limited to the reactor coolant system pressure boundary. The staff reviewed Section 3.2.4 of Appendix B of the LRA to determine whether the applicant has demonstrated that the Boric Acid Wastage Surveillance Program will adequately manage the applicable aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.5.4.1 Summary of Technical Information in the Application

In Section 3.2.4 of Appendix B of the LRA, the applicant states that the inspections are performed to provide reasonable assurance that borated water leakage does not lead to undetected loss of material from the reactor coolant pressure boundary and surrounding components.

This AMP was developed by the applicant in response to Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The applicant's program includes examination of primary coolant components for evidence of borated water leakage that could degrade the external surfaces of nearby structures or components and implementation of corrective actions to address coolant leakage. At a minimum, these activities are performed inside containment at the beginning and end of each refueling outage.

The following systems, structures, commodities, and major components credit this AMP for managing the aging effect of loss of material:

<u>Systems</u>

- chemical and volume control
- component cooling water
- containment cooling
- containment isolation
- containment spray
- containment post accident monitoring
- fire protection
- fuel pool cooling
- instrument air
- intake cooling water
- main feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine
- miscellaneous bulk gas supply
- primary makeup water
- reactor coolant
- safety injection
- sampling
- service water
- ventilation
- waste management

<u>Structures</u>

- containment
- fuel handling building
- reactor auxiliary building
- yard structures

The applicant states that the Boric Acid Wastage Surveillance Program is consistent with the 10 program elements of AMP XI.M10, “Boric Acid Corrosion,” as specified in the GALL Report dated April 2001. The current program will be implemented during the extended period of operation. The applicant states that commitment dates associated with implementation of this AMP are contained in Appendix A of the LRA.

3.0.5.4.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.4 of Appendix B of the LRA and the summary description of the Boric Acid Wastage Surveillance Program in the FSAR supplement, Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 of the LRA. The 10 program elements in GALL AMP XI.M10, “Boric Acid Corrosion,” provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage the aging effects in RCS components. In Appendix B, Section 3.2.4, of the LRA, the applicant stated that the program elements for the Boric Acid Wastage Surveillance Program are consistent with those specified in AMP XI.M10 of GALL. The applicant retains the program description of the Boric Acid Wastage Surveillance Program, as well as the descriptions of the program's 10 elements, on record at the St. Lucie Nuclear Station.

The staff inspected the Boric Acid Wastage Surveillance Program for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M10. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff's review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M10 in the FSAR supplements' descriptions of this AMP. This is confirmatory item 3.0.2.2-1

The applicant credits this program with monitoring borated water systems for leakage that could potentially affect systems and components credited with a license renewal function (in addition to systems and components inside the reactor coolant system pressure boundary). The staff's review of the Boric Acid Wastage Surveillance Program includes the applicant's operating experience regarding how the program manages aging effects in systems and components beyond the reactor coolant system pressure boundary.

The applicant states that the Boric Acid Wastage Surveillance Program has been an ongoing program since the startup of the plant. The program was implemented to manage aging effects for systems consistent with AMP XI.M10 in GALL and for systems included within the scope for license renewal as specified in Section 3.0.5.4.1 of this SER. A review of the operating experience by the applicant showed that, since the establishment of this program, there have not been any instances of boric acid corrosion that impacted license renewal system intended functions.

NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," was issued as a result of reactor pressure vessel head wastage that occurred due to control rod drive mechanism (CRDM) nozzle cracking at the Davis Besse Nuclear Power Plant. The plant identified severe degradation of the reactor vessel head due to exposure to concentrated boric acid. To date, all licensees have responded to the bulletin, providing information about their boric acid corrosion control (BACC) programs. However, the staff has determined that additional information from licensees is necessary because most of the licensees' responses to Bulletin 2002-01 lacked specificity, and therefore, the staff could not make a reasonable assurance finding that the BACC programs have been effective. This information request is necessary to permit the assessment of plant-specific compliance with NRC regulations. This information will also be used by the NRC staff to determine the need for, and to guide the development of, additional regulatory actions to prevent degradation of the reactor coolant pressure boundary.

The staff and nuclear power industry are pursuing resolution of the issue revealed by the Davis Besse event, and the staff is evaluating potential changes to the requirements governing inspections of Alloy 600 VHP nozzles and PWR upper RV heads (specifically with respect to non-destructive examinations and the ability to detecting cracking in the VHP nozzles prior to loss of materials in the upper RV heads). Because this is an emerging issue that has not yet been resolved, but will be resolved during the current license term, consideration of this issue is beyond that scope of this license renewal review, pursuant to 10 CFR 54.30(b).

3.0.5.4.3 FSAR Supplement

Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 of the LRA provide the applicant's FSAR supplements for the Boric Acid Wastage Surveillance Program. The staff reviewed the sections to verify that the information in the FSAR supplements provides an adequate summary of the program activities required by 10 CFR 54.21(d). The staff identified that the applicant needs to modify the FSAR supplements descriptions of the Boric Acid Wastage Surveillance Program to include portions of the waste management system within the scope of license renewal. This is confirmatory item 3.0.5.4-1. The applicant should also modify the FSAR in accordance with confirmatory item 3.0.2.2-1.

3.0.5.4.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.0.5.5 Chemistry Control Program–Water Chemistry Control Subprogram

The Chemistry Control Program–Water Chemistry Control Subprogram is described in Section 3.2.5.1, of Appendix B to the LRA. This program provides aging management of piping and associated components for St. Lucie, Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Chemistry Control Program–Water Chemistry Control Subprogram will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.5.1 Summary of Technical Information in the Application

In Section 3.2.5.1 of Appendix B to the LRA, the applicant states that aging effects will be managed by the Water Chemistry Control Subprogram to ensure that significant degradation is not occurring and the component intended function will be maintained during the period of extended operation.

The applicant states that the Water Chemistry Control Subprogram has been an ongoing program at St. Lucie since the initial startup and has evolved over many years of plant operation. The program provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished by effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. The applicant further states that chemistry data are also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect components' intended functions.

The applicant states that the Water Chemistry Control Subprogram is consistent with the 10 program elements of AMP XI.M2, "Water Chemistry," as specified in the GALL Report, dated

April 2001. The applicant also states that commitment dates associated with implementation of this AMP are contained in Appendix A of the LRA.

3.0.5.5.2 Staff Evaluation

The staff reviewed the information in Section 3.2.5.1 of Appendix B of the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions of the program in the FSAR supplement, Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the LRA. The 10 program elements in GALL AMP XI.M2, "Water Chemistry," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects of components in a fluid environment to minimize corrosion. In Appendix B, Section 3.2.5.1, of the LRA, the applicant has stated that the program elements for the Water Chemistry Control Subprogram are consistent with those specified in AMP XI.M2 of the GALL Report. The applicant retains the program description of the Water Chemistry Control Subprogram as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

In a discussion of operating experience, the applicant states that no special one-time inspection will be performed for the purpose of verifying the effectiveness of the Water Chemistry Control Subprogram. This position deviates from the GALL Report as it recommends the one-time inspection. However, the applicant states that internal surfaces of components are visually inspected for loss of material and other aging effects during routine and corrective maintenance requiring equipment disassembly.

By letter dated July 18, 2002, the staff issued RAI B.3.2.5-1. The RAI requested the applicant to clarify that those locations inspected during routine and corrective maintenance include representative susceptible locations (such as low-flow or stagnant areas). In addition, the applicant was requested to discuss past findings that demonstrate that routine and corrective maintenance verified the effectiveness of the water chemistry control subprogram.

In its response dated September 26, 2002, the applicant stated that routine preventive and corrective maintenance inspections do not specifically target components subject to low flow or other susceptible areas. However, the susceptible areas, such as low-flow areas and crevices associated with mechanical joints, will be exposed during the process of disassembling and be subject to inspection. Data and results from these inspections are documented. The ASME Boiler and Pressure Vessel Code Section XI requires an internal visual examination to determine the condition of Class 1 valve and pump internals at least once each inspection interval. The applicant stated that when significant corrosion or degraded parts are identified, the support of materials experts within FPL is typically requested to determine root cause. The applicant further stated that a review of plant-specific operating experience for the St. Lucie closed water systems had been performed to identify any age-related material failures associated with crevice corrosion or inadequate chemistry controls.

No instances of crevice corrosion in treated water systems or evidence of an ineffective Water Chemistry Control Subprogram was identified. This review included past material failures associated with various components including several in stagnant or low-flow areas (vent and drain lines and instrument lines). None of the failures associated with stagnant or low-flow lines was attributed to crevice corrosion or lack of chemistry controls.

The applicant implemented the Water Chemistry Control Subprogram since initial plant startup. Susceptible areas are routinely inspected under this program, which is comparable to a one-time inspection. In addition, the applicant's review of operating experience did not identify any evidence of an ineffective Water Chemistry Control Subprogram. Therefore, based on routine inspections of susceptible areas and operating experience, the staff finds the applicant's response to RAI B.3.2.5-1 adequate to resolve the issue.

The staff inspected the Water Chemistry Control Subprogram for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M2. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff's review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M2 in the FSAR supplements' description of this AMP. This is Confirmatory Item 3.0.2.2-1

3.0.5.5.3 FSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the Chemistry Control Programs at St. Lucie. The staff reviewed the sections to verify that the information in the FSAR supplements provides an adequate summary of the program activities required by 10 CFR 54.21(d). With the exception of confirmatory item 3.0.2.2-1, the staff finds the FSAR supplements sufficient.

3.0.5.5.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.0.5.6 Chemistry Control Program—Closed-Cycle Cooling Water System Chemistry Subprogram

The Chemistry Control Program–Closed-Cycle Cooling Water System Chemistry Subprogram is described in Section 3.2.5.2 of Appendix B to the LRA. This program provides aging management of piping and associated components for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Chemistry Control Program–Closed-Cycle Cooling Water System Chemistry Subprogram will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.6.1 Summary of Technical Information in the Application

In Section 3.2.5.2 of Appendix B to the LRA, the applicant states that aging effects will be managed by the Closed-Cycle Cooling Water System Chemistry Subprogram to ensure that significant degradation is not occurring and the components' intended function will be maintained during the period of extended operation.

The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram has been an ongoing program at St. Lucie since the initial startup and has evolved over many years of plant operation. The program provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished by effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. The applicant further states that chemistry data are also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect the components' intended functions.

The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the 10 program elements of Aging Management Program (AMP) XI.M21, "Closed-Cycle Cooling Water System," as specified in the GALL Report dated April 2001. The applicant also states that commitment dates associated with implementation of this AMP are contained in Appendix A of the LRA.

3.0.5.6.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.5.2 of the LRA, the applicant's responses to the staff's RAIs, and the summary descriptions of the Chemistry Control Program in the FSAR supplement, Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the LRA. The 10 program elements in GALL AMP XI.M21, "Closed-Cycle Cooling Water System," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects of components in a fluid environment to minimize corrosion. In Appendix B, Section 3.2.5.2, of the LRA, the applicant has stated that the program elements for the Closed-Cycle Cooling Water System Chemistry Subprogram are consistent with those specified in AMP XI.M21 of GALL. The applicant retains the program description of the Closed-Cycle Cooling Water System Chemistry Subprogram as well as the descriptions for the program's 10 elements, on record at the St. Lucie Nuclear Station.

The applicant credits the St. Lucie Water Chemistry Control Program–Closed-Cycle Cooling Water System Subprogram for managing loss of material due to general, pitting, and crevice corrosion in the cooling water system components exposed to treated water. These components are made of carbon steel, stainless steel, cast iron, and aluminum bronze. The applicant states that the Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the 10 attributes of the AMP X1.M21, "Closed-Cycle Cooling Water System," in the GALL Report, with the exception that this subprogram does not address surveillance testing and inspection. The applicant further states that the St. Lucie Intake Cooling Water Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program. However, the Intake Cooling Water Inspection Program includes inspection of only those closed-cycle cooling water (CCW) system components that are exposed to raw water, and not to treated water, which include the CCW heat exchanger tubes, tubesheets, channels, and doors. The GALL Report recommends inspecting these components and other CCW system components that are exposed to treated water and are susceptible to loss of material. By letter dated July 18, 2002, the staff requested, in RAI B.3.2.5-2, the applicant to provide justification for not including inspection in the aging management of the CCW components exposed to treated water.

In its response dated September 26, 2002, the applicant stated that a review of St. Lucie plant-specific operating experience was performed as part of the AMR process for CCW to identify any age-related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective chemistry control program. The applicant noted that many CCW components have been inspected in the past as part of corrective maintenance or the preventive maintenance program (e.g., periodic pump overhauls). The applicant further stated that during the past 12 months, more than 30 maintenance work orders were generated for Units 1 and 2 CCW that required disassembly or removal of components. These work orders included repairs on instrumentation and other isolation valves, flow control valves, and check valve and relief valve internal inspections throughout the system. A majority of these components (e.g., relief and isolation valves) entailed system locations where stagnant flow conditions exist. These locations are the likely candidates for pitting corrosion. The internal condition of the components has provided additional confidence that the Closed-Cycle Cooling Water System Chemistry Subprogram is effective.

The applicant stated that the St. Lucie maintenance procedures typically specify inspection criteria or reference plant quality instructions that specify internal cleanliness requirements. As an example, the maintenance procedure for relief valve removal and testing includes a visual inspection of valve and piping mating surfaces for corrosion and pitting. Additionally, the applicant referred to the response to RAI 3.3.2-1 for additional information regarding maintenance inspection requirements. The response to RAI 3.3.2-1 stated that the maintenance procedures specify Class C cleanliness requirements for CCW. Class C permits a tightly adhered oxide film or red oxide coating, as well as small areas of light rust, but pitting would not be acceptable. The applicant further stated that any significant degradation identified during these inspections would have been documented under the plant corrective action program. Therefore, the applicant concluded that the Closed-Cycle Cooling Water System Chemistry Subprogram is an effective program, and additional inspections of other CCW components specifically to confirm program effectiveness are unnecessary.

On the basis of its review, the staff finds that the applicant's response to RAI B.3.2.5-2 clarifies and satisfactorily resolves the item because some of the CCW locations with stagnant flow conditions that might be susceptible to pitting corrosion were included in the past maintenance activities, the connections between metals and nonmetals (e.g., flange connections associated with valves and pumps) that might be susceptible to crevice corrosion were also included in the maintenance activities, and no loss of material (corrosion damage) has been detected during activities to verify the effectiveness of the Closed-Cycle Cooling Water System Chemistry Subprogram.

The staff inspected the Closed-Cycle Cooling Water System Chemistry Subprogram for acceptability and compared the program's 10 elements to the 10 elements described in GALL AMP XI.M21. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff's review of the inspection findings is Open Item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the FSAR Supplements' descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.0.5.6.3 FSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the LRA provide the applicant's FSAR supplements for the Chemistry Control Programs at St. Lucie. The staff reviewed the sections to verify that the information in the FSAR supplements provides an adequate summary of the program activities required by 10 CFR 54.21(d). With the exception of confirmatory item 3.0.2.2-1, the staff finds the FSAR supplements sufficient.

3.0.5.6.4 Conclusions

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of Open tem 3.0.2.2-1.

3.0.5.7 Fire Protection Program

The Fire Protection Program is described in Section 3.2.8 of Appendix B to the LRA. This program provides aging management for the fire protection system and fire-rated assemblies. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Fire Protection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.7.1 Technical Information in the Application

The purpose of the Fire Protection Program is to manage loss of material and fouling of specific components in the fire protection systems exposed to raw water within the scope of license renewal. The program activities manage loss of material in sprinklers, which can affect the pressure boundary and spray functions of the sprinklers. The program activities also manage fouling of sprinklers, valves at hydrants, and valves at hose racks. The activities constitute a condition monitoring program that is credited with managing the subject aging effect for brass and bronze materials exposed to a raw water environment.

As identified in Chapter 3 of the LRA, the Fire Protection Program is credited for aging management of specific component/commodity groups in the fire protection system and the fire-rated assemblies.

This program is plant specific. The GALL Report contains two AMPs, XI.M26, "Fire Protection," and XI.M27, "Fire Water System." The St. Lucie Fire Protection Program combines the appropriate scope of the two GALL programs. In addition, FPL credits the Systems and Structures Monitoring Program, the Galvanic Corrosion Susceptibility Inspection Program, and the Boric Acid Wastage Surveillance Program for managing aging of the appropriate components of the fire protection system and fire-rated assemblies. Concrete and steel structural components that serve as fire barriers are addressed with their associated structure, as appropriate.

3.0.5.7.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.8 of Appendix B of the LRA; the applicant's September 26, 2002, response to the staff's RAIs; the applicant's November 27, 2002, letter providing supplements to its September 26, 2002, letter; and the UFSAR summary description of the Fire Protection Program in Appendix A of the LRA. As identified in Table 3.3-6 of the LRA, the Fire Protection Program is credited for aging management of specific component/commodity groups associated with the fire protection system and fire-rated assemblies. The staff evaluated the program against 10 elements that are described in Appendix A to NUREG-1800—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Fire Protection Program is credited for managing the aging effects of loss of material due to corrosion (including selective leaching), cracking, and fouling of the mechanical components of the fire protection system within the scope of license renewal. The mechanical components include valves (bodies only) and pumps (casings only), tanks, orifices, filters, piping, tubing, sprinkler heads, flexible hoses, halon system components, fire hydrants, vortex breakers, and sight glasses. Additionally, this program manages the aging effects of loss of material, loss of seal, cracking, and erosion for structures and structural components (e.g., seals) associated with fire protection. The LRA states that the program is also credited for managing loss of material due to corrosion of fire doors. The staff finds the scope of the Fire Protection Program acceptable because it covers the applicable aging effects for the components of the fire protection system and fire-rated assemblies.

Preventive Actions: Mechanical fire protection system components are periodically flushed, performance tested, and inspected. Many fire protection system components are provided with a protective coating to minimize the potential for external degradation. Although not credited for eliminating aging effects, coating minimizes corrosion by limiting exposure to the environment. The staff finds the preventive actions identified above adequate and acceptable.

Parameters Monitored or Inspected: The LRA states that surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material. Internal conditions are monitored through the use of leakage, flow, and pressure testing. Internal loss of material can be detected by changes in flow or pressure, leakage, or evidence of excessive corrosion products during flushing of the system.

In RAI B3.2.8-2, the staff requested that the applicant provide the extent of inspection for each type of penetration seal and the frequency of inspections and functional tests of the fire doors and seals. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant provided the following response:

> As stated in the response to RAI 3.5-3, and based on the information in SECY-96-146 and St. Lucie plant-specific operating experience fire barrier penetration seals do not experience aging effects that would lead to a loss of intended function. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.
>
> However, plant procedures do provide for the inspection of penetration seals. Currently, visual inspection of at least 10% of each type of sealed penetration is performed during each refueling outage. If changes in appearance or degradations are found, a visual inspection of an additional 10% of each type is made. The types of penetrations are defined as:

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

> This process continues until a 10% sample with no changes or degradation is found. Samples are selected such that each seal will be inspected at least once every fifteen years.
>
> The penetration seals and materials in use at St. Lucie are listed in LRA Table 3.5-8 (page 3.5-62), and St. Lucie Unit 1 UFSAR Appendix 9.5A, Section 3.14.3 (page 9.5A-136) and Unit 2 UFSAR Chapter 9.5A, Section 3.14 (page 9.5A-128).
>
> Plant procedures require that the penetration seals be visually inspected for voids, gaps, holes and indications of slippage. Additionally, both sides of a fire barrier are inspected unless it is inaccessible. Discrepant conditions are documented and evaluated in accordance with the corrective action program.
>
> Fire door inspection is currently conducted every six months.

The applicant's response satisfactorily addresses the staff's concerns, and the RAI issues are considered resolved. The staff finds that the parameters monitored will permit timely detection of the aging effects and are, therefore, acceptable.

Detection of Aging Effects: The LRA states that the detection of age-related degradation on external surfaces is determined by visual examination. Surfaces of 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.

In RAI B.3.2.8-1, the staff requested that the applicant provide justification for excluding loss of material due to microbiologically influenced corrosion or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water. In addition, the staff requested that the applicant clarify its position that the Fire Protection Program is consistent with the corresponding programs in the GALL Report. By letter dated September 26, 2002, the applicant provided the following response:

> Loss of material due to microbiologically influenced corrosion (MIC) has not been excluded as an aging effect requiring management for carbon steel and cast-iron components in fire protection systems. As discussed in LRA Appendix C, Section 5.1 (page C-13), MIC was considered an aging mechanism which causes loss of material for systems operating at temperatures less than 210 °F and pH less than 10. As a result, the aging management review of the fire protection system identified loss of material due to MIC as an aging effect requiring management for the internal surfaces of the cast iron and carbon steel components exposed to "Raw water-city water." Loss of material due to this aging mechanism is included on LRA Table 3.3-6 (pages 3.3-42 through 3.3-44).
>
> With respect to biofouling, as stated in LRA Appendix C, Section 5.3 (page C-15), biofouling is an aging effect due to an accumulation of macro-organisms. Fire Protection at St. Lucie uses water classified as "Raw water-city water." As stated in LRA Appendix C, Section 4.1.2 (page C-7), this water is potable water -- water that has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. Macro-organisms would not be found in water. Therefore, biofouling is not an aging effect requiring management.

> LRA Subsection 3.3.4 (page 3.3-11) incorrectly stated that the Fire Protection Program is consistent with the corresponding programs in the GALL Report. As stated in LRA Appendix B Section 3.2.8 (page B-39), the Fire Protection Program is plant-specific. Therefore, the list in LRA Subsection 3.3.4 (page 3.3-11) is revised to delete the Fire Protection Program from the list of St. Lucie programs that are consistent with the corresponding programs in the GALL Report, and revised to add the Fire Protection Program to the St. Lucie plant-specific programs list.

The applicant's response satisfactorily addresses the staff's concerns and the RAI issues are considered resolved.

In RAI B.3.2.8-3, the staff asked the applicant to discuss the program for internal inspections of the fire protection piping, as stated in Chapter XI.M27, "Fire Water Systems," of the GALL, and to explain how the program will detect wall thinning due to internal corrosion. Since opening the system results in the introduction of oxygen that may contribute to the initiation of general corrosion, the applicant was asked to explain why nonintrusive means of measuring wall thickness, such as ultrasonic inspection, are not used to manage this aging effect. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant stated that the internal loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. The applicant also stated that St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable. The staff does not find the applicant's response satisfactory because it does not explain the monitoring of the internal corrosion in the piping that is not subject to flow tests. Therefore, this remains open item 3.0.5.7-1.

With the exception of this open item, the staff finds the applicant's detection methods acceptable, since they are consistent with industry practice.

Monitoring and Trending: The LRA states that administrative procedures contain the regulatory commitments and surveillance requirements for the Fire Protection Program. The procedures governed by the Fire Protection Program require various testing, inspection, or surveillance frequencies. The frequency and scope of the testing, inspection, or surveillance associated with the Fire Protection Program are sufficient to identify effects of aging prior to compromising the integrity of the system or its intended function.

In RAI B.3.2.8-4, the staff asked the applicant to discuss the inspection activities that provide the reasonable assurance that the intended function of below-grade fire protection piping will be maintained consistent with the CLB for the period of extended operation. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant stated that internal and external conditions for below-grade fire protection piping are monitored via leakage, flow, and pressure testing. Internal and external loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable for fire protection system underground piping. The staff finds the applicant's response reasonable and acceptable and consistent with the staff position.

The staff finds that the applicant's methodology will provide effective monitoring and trending and is, therefore, acceptable.

Acceptance Criteria: The LRA states that the results of the testing, inspection, or surveillance will be evaluated in accordance with the acceptance criteria in the appropriate fire protection procedure(s). Degradation found as a result of the testing, inspection, or surveillance of the systems or components is entered into the corrective action program.

In RAI B.3.2.8-6, the staff asked the applicant to discuss the inspection plans for the sprinkler system during the current operating term, as well as during the extended period of operation. By letter dated November 27, 2002, the applicant provided the following response:

> For St. Lucie Unit 1, the oldest sprinkler heads were installed approximately one year prior to issuance of the St. Lucie Unit 1 Facility Operating License. Per St. Lucie Units 1 and 2 UFSARs, Appendix 9.5A, the St. Lucie Current Licensing Basis does not include NFPA25 for testing and inspection of sprinkler heads; however, St. Lucie generally conforms to NFPA guidelines. St. Lucie uses city water (potable) as its water source for the fire protection system. This water was conservatively classified as “raw water” for the purpose of performing aging management reviews even though it is clean and free of contaminants compared to lake or river water used in fire protection systems at other plants. The quality of the water minimizes loss of material, as evidenced by St. Lucie’s operating and maintenance experience. A fire protection system annual flush is credited for ensuring the system is clear of scale, debris and foreign material.
>
> For dry pipe closed head sprinkler systems, procedures verify the systems are in a state of readiness by ensuring proper operation of clapper/inlet valves, all nozzles are unobstructed, and that water and supervisory nitrogen pressure is available.
>
> For wet pipe closed head sprinkler systems, a procedure verifies that the system alarm functions and checks for water clarity.
>
> The results of a review of plant-specific operating history associated with the tests and inspections of these components did not identify any degraded conditions for the internal surfaces of these sprinklers.
>
> Based on feedback from meetings with NRC staff conducted during the review of the Turkey Point Unit 3 and 4 LRA review, and open items identified on previous license renewal applications, St. Lucie proposes to perform testing of wet pipe sprinkler heads following the guidance of NFPA 25 commencing in the year 2026 (50 years from the issuance of the original operating license on Unit 1). This enhancement will be included within the Fire Protection Program (LRA Appendix B Subsection 3.2.8, page B-39).

Considering the above, the staff finds that the testing of sprinkler heads will provide reasonable assurance that the sprinkler heads will be able to perform their intended function. The staff finds the acceptance criteria reasonable and acceptable.

Operating Experience: The LRA states that the Fire Protection Program has been an ongoing program at St. Lucie Units 1 and 2. This program was enhanced by implementation of 10 CFR 50, Appendix R, and has evolved under many years of plant operation. The program incorporates the best practices recommended by the NFPA and Nuclear Electric Insurance Limited (NEIL) and is approved by the NRC. The Fire Protection Program has been significantly enhanced since initial plant operation and has been effective at maintaining fire protection features by reliable performance.

The LRA further states that the overall effectiveness of the Fire Protection Program is demonstrated by the excellent operating experience of 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.

In RAI B.3.2.8-5, the staff asked the applicant to discuss the significant recent enhancements that resulted from these assessments, and to indicate whether or not these enhancements have received NRC approval. By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant provided the following response:

> There have been no recent enhancements to the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39). However, based on recent periodic internal and external assessments, fire protection plant modifications have been implemented including the replacement of all Unit 2 preaction suppression system local control panels with updated equipment, replacements of Unit 1 smoke detectors with new model detectors, replacement of both Control Room fire computers with new fire panels, extended preaction system coverage in the Units 1 and 2 cable loft areas, and upgraded penetration seals (cable tray fire stops) in Unit 2. St. Lucie Unit 1 UFSAR Appendix 9.5A and Unit 2 UFSAR Chapter 9.5A Fire Protection Program Report contain a review of Fire Protection and the Fire Protection Program with respect to the applicable codes and standards.
>
> As a result of NRC Generic Letter 92-08, corrective actions associated with Thermo-lag were initiated. The Thermo-lag corrective actions were completed and the NRC was notified (see R. S. Kundalkar (FPL) letter to NRC Document Control Desk, L-2000-83, St. Lucie Unit 1 Thermo-Lag 330-1 Summary Report, April 7, 2000 and J. A. Stall (FPL) letter to NRC Document Control Desk, L-98-165, St. Lucie Unit 2 Thermo-Lag 330-1 Summary Report, June 23, 1998).
>
> St. Lucie also performed NFPA Code reviews of the suppression and detection systems, and, based on the findings, further evaluations and modifications were implemented (e.g., increased radiant heat shield coverage in Unit 1 and 2 Containments and improved weather resistance of exterior smoke detection systems). The NRC reviewed some of the evaluations and modifications described above during the St. Lucie Fire Protection Functional Inspection conducted in 1998 (NRC Inspection Report Nos. 50-335/98-14, 50-389/98-14). Others have been implemented subsequent to this inspection. With respect to NRC review, all changes to the Fire Protection Program and/or system are reviewed in accordance with 10 CFR 50.59 and Facility Operating Licenses DPR-67 (Unit 1) Section C.(3) and NFP-16 (Unit 2) Section C.3.20.

The applicant's response satisfactorily addresses the staff's concerns, and the RAI is considered resolved. The staff finds that, based on the operating experience, there is reasonable assurance that the applicant will maintain the fire protection system during the extended period of operation.

3.0.5.7.3 FSAR Supplement

The staff reviewed the FSAR supplements in Appendix A of the LRA. The staff concludes that the information provided in the FSAR supplements is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of program activities, as required by 10 CFR 54.21(d).

3.0.5.7.4 Conclusions

The staff concludes that, with the exception of open item 3.0.5.7-1, the applicant has demonstrated that the aging effects associated with the Fire Protection Program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.5.8 Flow Accelerated Corrosion Program

The Flow Accelerated Corrosion Program is described in Section 3.2.9 of Appendix B to the LRA. This program provides aging management of the steam generator nozzles and piping in the main feedwater system, condensate system, extraction steam system, moisture separation reheater system, and feedwater heater drain system for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Flow Accelerated Corrosion Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.8.1 Summary of Technical Information in the Application

In Section 3.2.9 of Appendix B to the LRA, the applicant identified the Flow Accelerated Corrosion Program to manage the aging effects of systems and components subject to flow accelerated corrosion. Flow accelerated corrosion reduces pipe wall thickness due to the movement of steam or water in the pipe. Industry experience has shown that flow accelerated corrosion has affected steam generator nozzles and piping in the main feedwater system, condensate system, extraction steam system, moisture separation reheater system, and feedwater heater drain system.

The applicant stated that the Flow Accelerated Corrosion Program is consistent with the 10 attributes of the AMP XI.M17, “Flow Acceleration Corrosion,” specified in the GALL Report. The Flow Accelerated Corrosion Program has been an ongoing program at St. Lucie since the 1980s. The program was originally implemented as a result of steam leaks experienced in the industry, including at St. Lucie. The applicant formalized its Flow Accelerated Corrosion Program in response to NRC Generic Letter 89-09, “Flow Accelerated Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants.” The applicant continuously upgrades the Flow Accelerated Corrosion Program on the basis of industry experience and research.

3.0.5.8.2 Staff Evaluation

The staff reviewed the applicant’s Flow Accelerated Corrosion Program to determine whether the applicant has demonstrated that the aging effects on the systems and components caused by flow accelerated corrosion will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff focused its evaluation on how the Flow Accelerated Corrosion Program manages aging effects through the effective incorporation of the 10 elements shown in GALL XI.M17 (program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant has credited the Flow Accelerated Corrosion Program at St. Lucie for aging management of systems and components including main steam, auxiliary steam and turbine, main feedwater, steam generator blowdown, and steam generator nozzles of the reactor coolant system. In addition, the applicant will enhance the program to include small bore piping associated with elected steam traps and drain lines that are potentially susceptible to flow accelerated corrosion and external general corrosion. The applicant periodically examines various sections of susceptible piping to determine the effects of flow accelerated corrosion. Piping that is affected by flow accelerated corrosion is either repaired or replaced. Branch connections are examined as St. Lucie or industry experience requires. The applicant has generated condition reports for piping wall thicknesses that have been found to be below the screening criteria in the Flow Accelerated Corrosion Program. Since 1996, the applicant has replaced a small number of components due to flow accelerated corrosion, including main steam small bore piping, steam trap piping, and steam generator blowdown piping in Unit 1, and steam generator blowdown system piping in Unit 2.

The applicant has implemented the Flow Accelerated Corrosion Program in accordance with the EPRI guidelines provided in NSAC-202L-R2, “Recommendations for an Effective Flow Accelerated Corrosion Program.” The applicant has committed to complete the enhancement of the Flow Accelerated Corrosion Program prior to the end of the initial operating license term for St. Lucie Units 1 and 2. This commitment is documented in Section 18.2.9 of St. Lucie Unit 1 FSAR supplement and Section 18.2.8 of St. Lucie Unit 2 FSAR supplement. The applicant retains the program description of the Flow Accelerated Corrosion Program and the descriptions for the program’s 10 elements on record at the St. Lucie Nuclear Station.

The staff inspected the Flow Accelerated Corrosion Program for acceptability and compared the program’s 10 elements to the 10 elements described in GALL XI.M17. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff’s review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the FSAR Supplements’ descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.0.5.8.3 FSAR Supplement

Section 18.2.9 of Appendix A1 and Section 18.2.8 of Appendix A2 of the LRA provide the applicant’s FSAR supplements for the Flow Accelerated Corrosion Program. The staff reviewed the sections to verify that the information in the FSAR supplements provides an adequate summary of the program activities required by 10 CFR 54.21(d).   With the exception of confirmatory item 3.0.2.2-1, the staff finds the FSAR supplements sufficient.

3.0.5.8.4   Conclusions

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant’s claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of Open Item 3.0.2.2-1.

3.0.5.9 Periodic Surveillance and Preventive Maintenance Program

The applicant described its Periodic Surveillance and Preventive Maintenance Program in Section 3.2.11 of Appendix B of the LRA. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the aging effects on applicable systems and structures will be adequately managed by this program during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.9.1 Summary of Technical Information in Application

The applicant specified that the Periodic Surveillance and Preventive Maintenance Program applies to component/commodity groups in certain designated systems and structures. The program is intended for managing the aging effects of loss of material, cracking, fouling, loss of seal, and embrittlement of systems and structures. Activities of the program consist of periodic visual inspection of selected surfaces of specific components and structural components, or alternatively, their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program also includes leak inspections of limited portions of the chemical and volume control systems.

As identified in Chapter 3 of the LRA, the Periodic Surveillance and Preventive Maintenance Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

- 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

Structures

- containments
- fuel handling buildings
- reactor auxiliary buildings

The applicant indicated that the Periodic Surveillance and Preventive Maintenance Program is an established program and its effectiveness has been demonstrated by early detection of component surface defects for timely actions to ensure structural integrity. The applicant concludes that the program will ensure 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 during the period of extended operation.

3.0.5.9.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.11 of Appendix B of the LRA; the applicant's September 26, 2002, and supplemental November 27, 2002, responses to the staff's RAIs; and the summary description of the Periodic Surveillance and Preventive Maintenance Program in Appendix A of the LRA. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that intended function will be maintained consistent with the CLB throughout the period of extended operation for systems and structures included in the program. The staff evaluated the program against 10 elements described in Appendix A to NUREG-1800 (program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Periodic Surveillance and Preventive Maintenance Program is credited for managing the aging effects of loss of material, loss of seal, fouling (mechanical components only), and cracking of the component/commodity groups in the systems and structures listed above. The scope of the program provides for visual inspection and examination of surfaces of 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. The staff finds that the relevant systems and structures are included in the scope of the program and therefore the scope is adequate.

Preventive or Mitigative Actions: The LRA states that the preventive measures include charging pump block internal inspections for Unit 2 only, oil sampling, and water removal and replacement of specific structural components and component groups based on operating experience. However, the applicant provided limited information regarding the different attributes of the periodic surveillance and preventive maintenance program related to aging management of the instrument air system components. In RAI 3.2.11-2, the staff asked the applicant the following:

(1) Provide information about whether the program is based on the Instrument Society of America's Standard ISA-S7.0.1-1996, "Quality Standards for Instrument Air." Specifically, discuss whether the moisture content and particulate size in the instrument air are continuously monitored. In addition, provide the acceptance criteria for particulate size and oil content in the instrument air, how often the system is sampled to ensure that air quality is maintained.

(2) Provide information about the inspection and testing frequency used for the instrument air system components. Also, verify and indicate whether or not the program follows the recommendations made by the industry report issued by the Electric Power Research Institute (EPRI) as EPRI NP-7079, "Instrument Air Systems–A Guide for Power Plant Maintenance Personnel," 1990, or its 1998 revision (i.e., EPRI/NMAC TR-108147, 1998).

By letter dated September 26, 2002, the applicant provided the following response to item 1:

> Instrument Air at St. Lucie was redesigned in the late 1980s to address equipment related problems and industry issues identified by GL 88-14, “Instrument Air Supply System Problems Affecting Safety-Related Equipment.” These modifications included the replacement of the instrument air dryers with more effective desiccant dryers (including prefilter and after filters) and two new air compressors per unit with capacities and purification capabilities recommended by ANSI/ISA-S7.3, “Quality Standard for instrument Air, Instrument Society of America.” Instrument Air for St. Lucie Units 1 and 2 meets the air quality requirements of ANSI/ISA S7.3-1975, Quality Standard for Instrument Air.
>
> The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) is not based on the Instrument Society of America’s Standard ISA S7.0.1-1996. Although the moisture content and particulate size in Instrument Air are not continuously monitored, performance of the air dryers is monitored regularly via a dryer moisture indicator. The dryers are reconditioned as needed based on this indication. The instrument air compressors are of the oil-free type. Dewpoint is determined annually. Instrument air particulate and oil samples are also taken annually per chemistry department procedures. This frequency is based on the recommendations contained in ISA-RP 7.7 and St. Lucie plant-specific operating experience. The acceptance criteria for instrument air particulate size is three micrometers. The acceptance criteria for oil content is zero w/w or v/v (weight basis or volume basis). The acceptance criteria for dewpoint is 18 °F below the minimum local recorded ambient temperature at the plant site.

By letter dated September 26, 2002, the applicant provided the following response to item 2:

> The applicable instrument air components (compressors, dryers, receivers, etc.) are inspected on a 26 week interval. The Periodic Surveillance and Preventive Maintenance Program does generally follow several, but not all, of the inspection and testing/frequency recommendations in the EPRI NP-7079, “Instrument Air Systems - A Guide for Power Plant Maintenance Personnel.” Based on St. Lucie’s plant specific operating experience, this preventive maintenance interval is considered acceptable.

The staff finds that the applicant has satisfactorily responded to the staff’s concerns as discussed above, and the RAI issues are considered resolved. The staff also finds that the proposed preventive and mitigative actions in their entirety satisfy this program element.

[Parameters Monitored or Inspected] The LRA states that the surface conditions of 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. The staff finds that the parameters monitored and the inspections will effectively manage the aging effects; therefore, the staff finds them acceptable.

Detection of Aging Effects: The LRA states that the aging effects of concern will be detected by visual inspection of surfaces for evidence of corrosion, cracking, leakage, debris, and deterioration, and by monitoring fuel oil and hydraulic oil for contamination. For some equipment, aging effects are managed by periodic replacement in lieu of inspection or refurbishment. The staff finds that techniques used to detect aging effects are consistent with accepted engineering practice and satisfy this program element.

Monitoring and Trending: The LRA states that the inspections, replacements, and sampling activities associated with this program are performed at a specific frequency as listed in administrative procedures, and the results of these activities are documented. The program includes various frequencies depending upon the specific component and aging effects being managed and plant operating experience. Examples of inspections and activities in the Periodic Surveillance and Preventive Maintenance Program include inspection of diesel generator flexible hoses for cracking and inspection for loss of seal of air tight door seals and gaskets. The LRA further states that the frequency of preventive maintenance tasks may be adjusted, as necessary, based on future plant-specific performance and/or industry experience.

Since this is an existing program, in RAI 3.2.11-1, the staff asked the applicant to provide a brief description of how frequently the inspections are conducted and components are replaced. For preventive actions, the LRA states that preventive measures including charging pump block internal inspection (Unit 2 only), oil sampling and water removal, and replacement of specific structural components and component groups are based on operating experience. In parameters monitored or inspected, the LRA states that certain intake cooling water system components are replaced at a given frequency based on operating experience. In RAI 3.2.11-1, the staff asked the applicant to identify the specific frequencies of those component inspections and replacements, including how operating experience is used to determine the frequencies.

By letter dated September 26, 2002, the applicant provided the following response:

> The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) currently includes inspection frequencies ranging from 31 days to 10 years depending upon the specific component, the aging effect being managed, and plant-specific operating experience.
>
> Examples of inspections that are part of this program and their current frequencies are provided below:
>
> - Inspection of charging pump blocks (Unit 2 only) for cracking due to fatigue is currently performed on a 6 month frequency.
>
> - Inspection of diesel fuel oil storage tanks (DOSTs) for accumulated water is performed on a 92 day frequency for Unit 1 and on a 31 day frequency for Unit 2. This is performed by opening drains on the tanks.
>
> - Oil Sampling of the DOSTs in accordance with ASTM D2276-83 is performed on a 31 day frequency.
>
> Examples of component replacements include intake cooling water pumps and expansion joints, which are scheduled for replacement with new or refurbished equipment on a 96 month and 120 month frequency, respectively.
>
> Operating experience is used to determine preventive maintenance (PM) frequencies. For example, the inspections of charging pump 2A, 2B and 2C blocks are performed as part of the periodic pump valve inspection/overhaul PM activities. Past inspections of blocks during these PM activities have been effective in identifying initiation of cracking in high stress sites. Based upon the service life of the charging pump valves, the frequencies of these PM activities were determined to provide for an early indication of internal fatigue cracking of the blocks.
>
> Water removal and oil sampling of the DOSTs are performed on a frequency as required by the Plant Technical Specifications. Based upon the condition of emergency diesel components as evidenced by past inspections, the frequency of this PM activity is adequate to preclude aging effects associated with loss of material.
>
> The frequencies of overhauls for the ICW pumps and the replacements of discharge expansion joints have been determined based upon the results of past component inspections and consider

> vendor recommendations. The frequency of the ICW pump overhauls ensures that coating degradations and loss of material due to exposure to the saltwater environment are adequately managed to preclude loss of intended function of the pumps. Likewise, the frequency for replacement of the discharge expansion joints ensures that cracking due to embrittlement is adequately managed.
>
> The frequencies of these tasks may be adjusted as necessary based on future St. Lucie plant-specific performance and/or industry experience. For example, if an enhanced ICW pump coatings product/installation technique demonstrates increased protection of susceptible pump materials, the frequency of periodic overhauls may be increased provided there are no other limiting factors associated with the current frequency.

The staff finds that the applicant has satisfactorily responded to the staff's concerns as discussed above. The issues related to RAI 3.2.11-1 are, therefore, considered resolved. The overall monitoring and trending techniques proposed by the applicant are considered acceptable because inspections, replacements, and sampling activities will effectively manage the applicable aging effects.

Acceptance Criteria: The LRA states that the acceptance criteria and guidelines for the visual inspections are provided in the procedures and preventive maintenance tasks. Acceptance criteria are tailored for each individual inspection considering the aging effect being managed. Examples in the LRA include:

- Inspections for loss of material provide guidance that requires evaluation under the corrective action program if there is evidence of loss of material beyond uniform light surface corrosion.

- Visually detectable cracking requires evaluation under the corrective action program.

- Refurbishments and replacements are performed at a specified frequency based on plant experience or equipment supplier recommendations.

For the staff to make a finding that the acceptance criteria are adequate to manage the aging of components and structures that credit this program, the staff performed an inspection of the procedures associated with the Periodic Surveillance and Preventive Maintenance Program. With the exception of confirmation item 3.0.2.2-1, the inspectors determined that the acceptance criteria are adequate to manage the aging of structures and components.

Operating Experience: The LRA states that the Periodic Surveillance and Preventive Maintenance Program is an established program at St. Lucie. It utilizes as its bases various industry standards, including regulatory guidelines. The effectiveness and continuous improvement of the Periodic Surveillance and Preventive Maintenance Program is supported by the improved material condition and reliability of the systems and structures that rely on the program, as is documented by internal as well as external assessments during the last several years. The staff finds that the operating experience supports the applicant's conclusion that this program will adequately manage the aging effects of the specified systems, structures, and components.

3.0.5.9.3 FSAR Supplements

The staff reviewed the summary description of the Periodic Surveillance and Preventive Maintenance Program in the FSAR supplements in Section 18.2.11 of Appendix A1 and Section 18.2.10 of Appendix A2 of the LRA. The staff finds that the information provided in the FSAR supplements for the aging management of systems and structures discussed above adequately summarizes the program activities as required by 10 CFR 54.21(d).

3.0.5.9.4 Conclusions

Pending the results of the NRC onsite inspection, the staff finds that the Periodic Surveillance and Preventive Maintenance Program will adequately manage the aging effects such that there is reasonable assurance that the intended functions of the systems and components that credit the program will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the systems and structures discussed above as required by 10 CFR 54.21(d).

3.0.5.10 Systems and Structures Monitoring Program

The Systems and Structures Monitoring Program is described in Section 3.2.14 of Appendix B to the LRA. This aging management program is consistent with the structural aspects of the GALL Report AMP XI.S6, “Structures Monitoring Program. However, the applicant’s program is plant specific. The Systems and Structures Monitoring Program provides for condition monitoring of components within several plant systems and structures that are within the scope of license renewal. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Systems and Structures Monitoring Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.5.10.1 Summary of Technical Information in the Application

Section 3.2.14 of Appendix B of the LRA states that the Systems and Structures Monitoring Program provides for condition monitoring of accessible surfaces of systems, structures, and components, including welds and bolting. The components comprising the following systems are monitored by this aging management program:

- auxiliary feedwater condensate
- chemical and volume control
- component cooling water
- containment cooling
- containment isolation
- containment spray
- diesel generator and support systems
- fire protection
- fuel pool cooling
- instrument air
- intake cooling water
- main feedwater and steam generator blowdown
- main steam, auxiliary steam, and turbine

- miscellaneous bulk gas supply
- primary makeup water
- safety injection
- turbine cooling water (Unit 1)
- ventilation
- waste management

In addition, the aging effects for the structural components in the following structures are managed by the Systems and Structures Monitoring Program:

- component cooling water areas
- condensate storage tank enclosures
- containments
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fuel handling buildings
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

The aging effects managed by the Systems and Structures Monitoring Program are (1) loss of material, (2) cracking, (3) fouling (mechanical components only), (4) loss of seal, and (5) change in material properties. The program utilizes inspections to identify aging effects prior to loss of intended function.

3.0.5.10.2 Staff Evaluation

The staff reviewed the information provided in Section 3.2.14 of Appendix B of the LRA; the applicant's September 26, 2002, and supplemental November 27, 2002, responses to the staff's RAIs; and the summary description of the Systems and Structures Monitoring Program in Appendix A of the LRA. The staff's evaluation of the Systems and Structures Monitoring Program focused on how the applicant demonstrates that the applicable aging effects of the structures and components that credit this program will be managed during the period of extended operation. The staff evaluated the program against the 10 elements that are described in Appendix A of NUREG-1800; the Standard Review Plan for License Renewal. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: Section 3.2.14 of Appendix B of the LRA, identifies (1) loss of material, (2) cracking, (3) fouling (mechanical components only), (4) loss of seal, and (5) change in material properties as the aging effects managed by the Systems and Structures Monitoring Program. The Systems and Structures Monitoring Program relies on visual inspection and examination of accessible surfaces of systems, structures, and components. The scope of the Systems and

Structures Monitoring Program includes inspection of insulated piping and equipment. Inspection of insulated equipment is performed by removal of the insulation to gain appropriate visual access to the equipment. In addition, computed radiography may be used to determine if significant external corrosion is present on insulated equipment. The Systems and Structures Monitoring Program also includes leak inspection of selected intake cooling water system and chemical and volume control system valves, piping, and fittings.

As a result of RAI 3.5-1, several additional concrete components now credit the Systems and Structures Monitoring Program. Specifically, in response to RAI 3.5-1, by letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant committed to monitor change in material properties, cracking, and loss of material for accessible reinforced concrete and masonry block structures. The Systems and Structures Monitoring Program includes a walkdown inspection and aging effects assessment of structures and components. With the addition of these structural concrete components, the staff finds that the scope of the Systems and Structures Monitoring Program is acceptable since it includes all the components subject to the aging management effects, which this program is intended to manage.

With the addition of these structural concrete components, the staff finds the scope of the Systems and Structures Monitoring Program to be acceptable since it includes a visual inspection of all the structures and components and an assessment of the aging effects identified for these components by the applicant’s aging management review.

Preventive Actions: The applicant identified condition monitoring as the only inspection activity of the Systems and Structures Monitoring Program and states that no preventive actions are taken as a part of this AMP. The staff concurs with this position.

Parameters Monitored and Inspected: Section 3.2.14 of Appendix B of the LRA, states that the Systems and Structures Monitoring Program provides a visual inspection of the conditions of structures, system components, piping, and supports to determine the existence of external corrosion and in some cases internal corrosion. The application states that steel structures and components are monitored for evidence of corrosion, flaking, pitting, gouges, cracking, and other surface irregularities. The monitoring of concrete structural components is consistent with the guidelines provided in 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.” Concrete and masonry components are examined for evidence of exposed rebar, cracking, rust bleeding, spalling, scaling, other surface irregularities, and settlement. In addition, Section 3.2.14 of Appendix B of the LRA states that system commodity and component surface condition are inspected for corrosion, cracking, fouling, other surface irregularities, and leakage for selected systems.

For inaccessible components, the applicant intends to inspect accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components. For inaccessible concrete structural components, the applicant intends to enhance their Systems and Structures Monitoring Program for license renewal activities by providing additional guidance for inspections during the period of extended operation. In RAI B.3.2.14-2, the staff requested further information regarding these planned enhancements for inspecting inaccessible concrete. The applicant responded by letter dated September 26, 2002, stating that concrete surfaces below ground water require specifically tailored inspection criteria. In particular, the applicant stated that some interior portions of the reactor auxiliary building are below ground water and accessible for inspection. The applicant intends to inspect these interior portions of the reactor auxiliary building and use their material condition as an indicator for other below-grade inaccessible concrete components. In addition, the applicant stated that examination of representative samples of below grade concrete, when excavated for any reason, will be included as part of the Systems and Structures Monitoring Program.

The staff concurs with the applicant's approach to inspecting normally inaccessible structures and components as indicated above. The use of accessible components and similar material and environment as indicators for aging of inaccessible components is an approach that has been used by previous applicants and has been accepted by the staff. For accessible components, the staff finds that the parameters monitored by the Systems and Structures Monitoring Program, such as cracking and corrosion of external surfaces, are acceptable because they are directly related to the degradation of structures and components, and visual inspections are effective and adequate to detect such conditions.

Detection of Aging Effects: Section 3.2.14 of Appendix B of the LRA states that the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties are detected by visual inspection of surfaces for evidence of degradation or leakage.

Several components in the intake cooling water system credit the Systems and Structures Monitoring Program for managing loss of material in the raw water environment. In RAI B.2.10-2, the staff asked the applicant to provide the applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the intake cooling water system (cast iron, carbon steel, bronze, Monel, and stainless steel valves, piping, tubing, and fittings; stainless steel orifices; and stainless steel thermowells exposed internally to the raw water environment). In its response dated September 26, 2002, the applicant provided the following information:

> As described in LRA Appendix B, Section 3.2.14 (page B-58,) the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping and fittings at selected locations of Intake Cooling Water (ICW) by leakage inspection to detect the presence of internal corrosion. Loss of material for orifices, thermowells, and tubing/fittings due to internal exposure to raw water is also managed by leakage inspection via the Systems and Structures Monitoring Program as listed in LRA Table 3.3-9 (pages 3.3-60 and 3.3-61). Leakage inspection of ICW orifices, thermowells, and tubing/fittings was inadvertently omitted from the Systems and Structures Monitoring Program description in LRA Appendix B. These locations mostly encompass small bore piping components not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4" instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the Component Cooling Water heat exchangers below design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:
>
> - Maintenance history shows that localized failures of cement lining result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage, which provides adequate time for repairs before the system function is degraded.
>
> - For small valves, piping/tubing/fittings, thermowells, and orifices leakage does not affect the system function because the small size of these components limits the leakage. The

> > St. Lucie plant-specific operating experience for these components demonstrates that leakage for this equipment has not been significant.
>
> The leakage inspection is currently performed at least once per 18 months. This frequency is based on St. Lucie plant-specific operating experience. The frequency of inspections may be adjusted as necessary based on future inspection results and industry experience.

The staff finds the applicant's response, as discussed above, does not adequately address the aging management of the small valves, piping/tubing/fittings, thermowells, and orifices. Further information was provided by letter dated November 27, 2002, describing the materials, operating history, and repair history of the small piping and components in the intake cooling water system, but the applicant continues to rely on leakage detection for aging management. It is the staff's position that leakage detection does not provide adequate aging management because leakage indicates a loss of component intended function. This is open item 3.0.5.10-1.

Monitoring and Trending: Section 3.2.14 of Appendix B of the LRA states that the frequency of inspections varies depending on the system, structure, or component being inspected. The application states that the documented results of the visual inspections are used together with industry experience to determine if the frequency of scheduled inspections should be adjusted.

In RAI B.3.2.14-1, the staff requested that the applicant provide more detail regarding the inspection intervals and sample sizes for the structures, systems, and components (SSCs) that credit the Systems and Structures Monitoring Program. By letter dated September 26, 2002, the applicant stated that inspections carried out by the Systems and Structures Monitoring Program will be initially performed at a frequency of 5 years. However, leakage inspection of the intake cooling water will be performed at an 18-month frequency. In general, the frequency of inspections may be adjusted as necessary based on future inspection results and industry experience. The applicant further stated that sampling will not be used for the Systems and Structures Monitoring Program; however, sampling may be implemented in the future if the inspection results warrant this approach.

The staff finds an inspection schedule of at least once every 5 years to be sufficient for the aging management of components that credit the Systems and Structures Monitoring Program. Also, the applicant's commitment to adjust the inspection frequency based on inspection results and industry experience is acceptable to the staff.

Acceptance Criteria: The applicant identified general acceptance criteria in its description of the Systems and Structures Monitoring Program in the LRA. Specifically, Section 3.2.14 of Appendix B of the LRA states that detailed structural and system or component material condition inspections are performed in accordance with approved plant procedures. Existing procedures include detailed guidance for inspecting and evaluating the material condition of 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.

For the staff to make a finding that the above acceptance criteria are adequate to detect the aging of component groups that credit this program, the staff inspected the procedures associated with the Systems and Structures Monitoring Program. In particular, the staff reviewed the forms used to document the assessment of the material condition of components, as well as the system checklists used for documenting relevant information from system walkdowns. The staff inspection also reviewed the procedures associated with the Systems and Structures Monitoring Program to determine the level of detail, the specific parameters to be monitored for each component type, and the criteria used to evaluate an identified degradation.

The NRC staff inspection team found the procedures associated with the Systems and Structures Monitoring Program to be acceptable in terms of their detail and completeness. Inspection checklists for reinforced concrete, masonry, structural steel, and roofing materials were among those examined by the inspection team and found to be adequate. In addition, the inspection team reviewed the applicant's condition reports, which provides a process by which any conditions of concern may be identified, tracked, evaluated, and corrected. As a result of the review, the inspection team concluded that the plant procedures for the Systems and Structures Monitoring Program, with their associated acceptance criteria, contain detailed guidance that includes specific parameters and criteria for evaluating an identified degradation. With the exception of open item 3.0.2.2-1, the staff concludes that the acceptance criteria for the Systems and Structures Monitoring Program provides reasonable assurance that observed degradation of the structural components managed by this program will be adequately evaluated such that these structural components will continue to perform their intended functions during the period of extended operation.

Operating Experience: In Section 3.2.14 of Appendix B of the LRA, the applicant stated that the Systems and Structures Monitoring Program has been an ongoing program at St. Lucie and has been enhanced over the years to include the best practices recommended by industry guidance. Inspection findings, such as degraded conditions, are documented in accordance with the plant corrective action program in order to prevent recurrence by either plant modifications or program enhancements.

In RAI B.3.2.14-3, the staff requested that the applicant provide specific examples of enhancements and improvements that have been made to the Systems and Structures Monitoring Program as a result of previous inspection findings. By letter dated September 26, 2002, the applicant stated that examples of program enhancements due to observed degradation include increased inspections of the intake structure concrete, as well as more frequent inspections of steel components that have been more susceptible to corrosion. The staff finds the above enhancements to the Systems and Structures Monitoring Program to be acceptable examples of the type of program enhancements that are necessary to ensure that the aging of components that credit the Systems and Structures Monitoring Program are adequately managed.

In RAI B.3.2.14-2, the staff requested that the applicant provide further details regarding past inspections of inaccessible concrete structural components, which may be subjected to aggressive chemical attack due to the chemistry (pH, sulfides, chlorides) of the ground water. By letter dated September 26, 2002, the applicant stated:

> Inaccessible concrete has been inspected during past excavation activities and no concrete degradation was noted. Specifically, a portion of the below grade Containment Shield Building was exposed during the Unit 1 Steam Generator Replacement Project in 1997. Also, portions of the Unit 1 Cask Crane foundations and the Unit 1 Component Cooling Water structure below grade concrete were exposed during exploratory excavations associated with the Unit 1 Cask Crane replacement in 2002.

The applicant's response that no degradation of below-grade concrete has been observed is acceptable to the staff. The applicant has committed to enhance the Systems and Structures Monitoring Program by developing "specifically tailored inspection criteria" to manage the aging of inaccessible concrete components. A description of this enhancement is provided above under the parameters monitored or inspected subsection.

In conclusion, the staff finds that the applicant's operating experience has demonstrated that the Systems and Structures Monitoring Program has effectively maintained the integrity of the SSCs that currently credit this program, and that the effects of aging will be adequately managed so that there is reasonable assurance that the structure and component intended function(s) will be maintained during the period of extended operation.

3.0.5.10.3 FSAR Supplement

The staff reviewed the summary description of the Systems and Structures Monitoring Program in the FSAR supplement in Section 18.2.14 of Appendix A1 and Section 18.2.13 of Appendix A2 of the LRA. The staff finds that the information provided in the FSAR supplements for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities as required by 10 CFR 54.21(d).

3.0.5.10.4 Conclusion

With the exception of open item 3.0.5.10-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the Systems and Structures Monitoring Program will be adequately managed so that there is reasonable assurance that the intended functions of the structures and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplements in Appendix A of the LRA contain an appropriate summary description of the programs and activities for managing the effects of aging for the structures and components discussed above as required by 10 CFR 54.21(d).

3.1 Aging Management of Reactor Coolant System

In section 3.1 of the LRA, the applicant identifies the following reactor coolant system (RCS) mechanical components subject to an ARM:

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

The applicant described the results from the AMR for the Class 1 portions of the RCS, including the reactor vessels, reactor vessel internals, pressurizers, steam generators, and Class 1 piping, valves, and pumps in Section 3, "Reactor Coolant Systems," of the LRA. In Table 3.1-1, "Reactor Coolant Systems," of the LRA, the applicant summarizes the results from the AMR for these RCS components. The applicant describes the applicable AMPs for these components in Appendix B of the LRA, "Aging Management Programs." This section of the SER includes the staff's review of the AMR results presented in Section 3.1 of the LRA and includes the mechanical components for the RCS subsystems identified above.

3.1.0 System-Specific Aging Management Programs

3.1.0.1 Alloy 600 Inspection Program

3.1.0.1.1 Summary of Technical Information in the Application

The applicant states that the objective of the applicant's Alloy 600 Inspection Program (A600IP) is to manage the aging effect of cracking due to primary water stress corrosion cracking (PWSCC) by utilizing the walkdown inspections, which include visual inspections of the reactor vessel head external surfaces and other susceptible leakage locations in the reactor coolant system. The program also includes those reactor vessel head inspections to be performed in accordance with the applicant's commitments to NRC Generic Letter (GL) 97-01 and NRC Bulletin 2001-01. The scope and schedule of future reactor vessel head penetration inspection requirements are pending the issuance of industry guidance.

The applicant states that the scope of the A600IP encompasses the Alloy 600 RCS 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.

3.1.0.1.2 Staff Evaluation

The applicant describes the A600IP in Section B.3.2.1 of Appendix B of the LRA. The applicant also describes the A600IP in terms of the program attributes that would ensure that the A600IP would be sufficient to monitor and control cracking in the Alloy 600 penetration nozzles of the reactor coolant pressure boundary.

The staff's original basis for inspecting Alloy 600 RVH penetration nozzles in U.S. PWRs is provided in GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Head Penetrations" (April 1, 1997). Between November 2000 and April 2001, subsequent to the issuance of GL 97-01, reactor coolant pressure boundary (RCPB) leakage was identified from the reactor vessel head (RVH) penetration nozzles of four U.S. PWR-design light water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These findings are significant in that the cracking was reported to initiate from the OD side of the nozzle, either in the associated J-groove welds or heat-affect-zones, and not from the inside surface of the nozzles as was assumed in the industry responses to NRC Generic Letter (GL) 97-01. In regard to this experience, the degradation was severe enough to penetrate through the RCPB for the nozzles and represented the first report of circumferential cracking in U.S. RVH penetration nozzles. In NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" (August 3, 2001), the staff discussed the generic safety significance and impacts of these events on RVH penetration nozzles and recommended that the enhanced visual examination or volumetric examination methods be used for the inspection of RVH penetration nozzles.

In March 2002, during a refueling outage at the Davis Besse nuclear power plant, the licensee for the plant reported the occurrence of reactor coolant leakage from a number of the plant's RVH penetration nozzles. As a result of follow-up evaluations of the reactor coolant leakage, the license reported that, in one of the nozzles, the leakage resulted in significant boric-acid-related wastage of the RVH. The degree of degradation of the boric-acid-related wastage reduced the effective thickness of the RVH to below the minimum allowable wall thickness for the Class 1 pressure boundary component. On March 18, 2002, the NRC issued NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," to owners of pressurized water reactor (PWR) designs, requesting that the licensees address the impact of the Davis Besse event on the structural integrity of their RVHs and associated penetration nozzles. On August 9, 2002, the staff issued NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," to address additional technical issues resulting from the Davis Besse event. In Bulletin 2002-02, the staff specifically recommended that further augmented inspections, more comprehensive than those recommended in NRC Bulletin 2001-01, be performed on RVH penetration nozzles.

An additional operating issue related to PWSCC of Class 1 nickel-based alloy components was discovered during the V. C. Summer refueling outage 12 (October, 2000). During the PWSCC event at V. C. Summer, the licensee for the plant detected a through-wall crack in the reactor vessel hot-leg piping. Specifically, the crack was located in the first weld between the reactor vessel nozzle and the "A" loop hot leg piping, approximately 3 feet from the reactor vessel. The weld was fabricated from Alloy 82/182, which is an Inconel weld material. The licensee's metallurgical evaluation showed the crack was axially oriented with a length of about 2.5 inches and was connected to a small weep-hole on the outside surface of the weld. The failure mode was determined to be PWSCC, and the root cause of the cracking was attributed to the presence of high residual stresses resulting from extensive repairs of the subject weld.
The safety significance of the V. C. Summer cracking event is discussed in NRC Information Notice 2000-17, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer" (October 18, 2000), and 2000-01, Supplement 1, "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer" (November 16, 2000).

The aging of RVH penetration nozzles and other Class 1 components made from nickel-based alloys due to primary water stress corrosion cracking (PWSCC) is an emerging issue that is currently being evaluated and resolved by the NRC and the industry. The Davis Besse event raises an issue regarding the ability of the St. Lucie A600IP to implement inspection methods that are capable of detecting PWSCC in Class 1 nickel-based alloy components because the A600IP relies on visual examinations methods for the St. Lucie RVH penetration nozzles. Therefore, the impacts of the Davis Besse event and other nickel-based alloy operating experience must be taken into account to ensure that the applicant's A600IP will be capable of managing PWSCC in the Class 1 nickel-based alloy components of St. Lucie Unit 1 and 2. The staff assesses the following program attributes for the A600IP, as impacted by the events and generic communications discussed above, in the paragraphs that follow.

- Scope of Program
- Preventive Actions

- Parameters Monitored and Inspected
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria
- Operating Experience

The staff assesses the Corrective Actions, Confirmatory Actions, and Administrative Controls program attributes for the A600IP as part of the staff's assessment of the applicant's Quality Assurance Program, which is evaluated in Section 3.0.4 of this SER.

Scope of Program: The applicant stated that the A600IP is a plant-specific program that is designed to detect PWSCC in the Alloy 600 components that serve a pressure boundary function for the St. Lucie RCSs. The GALL Report (NUREG-1801) includes an Aging Management Program X.M11, "Nickel-Alloy Nozzles and Penetrations," which applies primarily to the reactor vessel head penetrations. The scope of the A600IP program includes the Alloy 600 Class 1 RCS components listed in Section 3.1.1.1 of this SER and the scope of the A600IP also incorporates FPL's responses to NRC GL 97-01 and NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." Aging effects in the St. Lucie Alloy 600 steam generator tubes are monitored by the applicant's Steam Generator Surveillance Program.

The "Scope of Program" program attribute for the A600IP, as submitted with the original application, did not include NRC Bulletins 2002-01 or 2002-02 as part of the CLB for the A600IP. Therefore, in RAI B.3.2.1-1, the staff requested the following actions of the applicant:

- Update your [Scoping] program attribute to include your response to NRC Bulletin 2002-01 (dated April 2, 2002, in FPL letter L-2002-061).

- Either summarize the scope and results of inservice and additional augmented (if applicable) examinations that have been performed on the St. Lucie Units 1 and 2 RVHs to date and comment on the impact the inspection results will have on the program attributes for the A600IP, or if your responses to NRC Generic Letter 97-01 and NRC Bulletin 2001-01 provides this type of information, reference that information in your responses to these generic communications summarizes both inspection results performed to date on the St. Lucie RVHs and addresses the impact of non-destructive examinations of the structural integrity of the St. Lucie RVHs and associated penetration nozzles.

In its response to RAI B.3.2.1-1, dated September 26, 2002, the applicant stated that it will continue to be a participant in the industry programs for assessing and managing PWSCC in Alloy 600 RVH penetration nozzles. The applicant emphasized in its response to RAI B.3.2.1-1 that the work performed by the EPRI MRP and NEI in assessment of this issue is an integral part of the A600IP and that the applicant's commitments made in response to NRC requests regarding this issue are considered to be part of the program. The applicant therefore clarified that the scope of the A600IP includes the applicant's response to NRC Bulletin 2002-01 (FPL letters L-2002-061 and L-2002-116 dated April 2, 2002, and June 27, 2002, respectively) and responses and commitments made to NRC Bulletin 2002-02 (FPL letter L-2002-185 dated September 11, 2002). This response updates the "Scope of Program" program attribute for the A600IP to the most current CLB for the RVH penetation nozzles and is therefore acceptable.

In Table 3.1.3-1 of the application, the applicant did not list the A600IP as an applicable program for managing cracking in Alloy 600 RCS flow baffles, core stabilizing lugs, and core stop lugs. Instead, the applicant identifies that it will use the Chemistry Control Programs and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Programs to manage cracking in these components. Table 3.1.3-1 indicates that the RCS flow baffles serve a flow distribution function, and the core stabilizing lugs and core stop lugs serve a core support function. Since neither of these components serves a pressure boundary function for the RCS, they are not within the scope of the A600IP.   This is acceptable to the staff.

Preventive Actions: The A600IP includes several actions for mitigating or preventing the initiation of PWSCC, including:

- Nickel plating of the surfaces of Alloy 600 components that are exposed to treated water

- Replacement of leaking Alloy 600 instrument nozzles with Alloy 690 material

- Preventive replacement of selected pressurizer and RCS piping instrument nozzles with Alloy 690 material

Pure nickel (i.e., nickel in its elemental form) is highly resistant to corrosive mechanisms, including general corrosion and stress corrosion cracking. The applicant considers an electrochemical potential of -200 MeV to be the threshold for initiation and growth of stress corrosion cracks in Alloy 600 material.   The staff concurs with this value as the threshold for initiation and growth of stress corrosion cracks in Alloy 600 materials under PWR primary water environments. At electrochemical potentials less than -200 MeV, the staff considers that the potential for initiating and growing stress corrosion cracks in Alloy 600 is inhibited. Plating of the nickel onto the Alloy 600 surfaces blocks the Alloy 600 surfaces from being exposed to the reactor coolant (i.e., to borated treated water) and lowers the electrochemical potential of the component below this level. The staff considers that Alloy 690 has improved resistance to stress corrosion cracking in comparison to Alloy 600. Replacing the instrument nozzles with nozzles fabricated of Alloy 690 should improve the resistance of the nozzles to stress corrosion over time. The staff concurs that these practices are acceptable mitigative practices and therefore concludes that the preventive action is acceptable.

Parameters Monitored or Inspected: The applicant states that the program monitors the effect of PWSCC on the intended function of the affected components by detection of cracks and identification of reactor coolant leakage. In Section 5.1 of the LRA, the applicant states that pitting is normally an issue only when the dissolved halide and oxygen concentrations in a coolant are in excess of 100 ppb or the dissolved sulfate concentrations are in excess of 150 ppb. The applicant implements the water chemistry program, as discussed in Section B.3.2.5.1 of the LRA, to ensure that the concentrations of these impurities for the RCS coolant are not in excess of these concentrations. The applicant therefore provides an acceptable basis in Section 5.1 of the LRA for concluding that pitting and crevice corrosion are not applicable effects for Alloy 600 components within the scope of the A600IP. The aging effects monitored by the A600IP are consistent with those evaluated by and accepted by the staff in Sections 3.1.1.1.2, 3.1.2.2.2, and 3.1.3.2 of this SER and are those identified in Section IV of the GALL Report, Volume 2, for Alloy 600 Class 1 piping, pressurizer, and RV components. The aging effect monitored by the A600IP (i.e., cracking) is therefore acceptable to the staff. The Steam Generator (SG) Surveillance Program is credited with managing cracking and loss of material in the St. Lucie Alloy 600 SG tubes. The staff evaluates the SG Surveillance

Program in Section 3.1.6.2.2 of this SER. The staff assesses the water chemistry program in Section 3.0.3 of this SER.

Detection of Aging Effects and Monitoring and Trending: The applicant stated that visual inspections of 100 percent of the Unit 1 and 2 reactor vessel heads will be conducted in accordance with the applicant's commitments to NRC Bulletins 2001-01 and 2002-02. The applicant indicated that the results of the inspections will be utilized to determine the need for additional bare metal visual or volumetric examinations.

The applicant also stated that leak tests and walkdowns are used for detecting through-wall PWSCC of Alloy 600 components. The leak tests consist of visual inspections of each susceptible location in accordance with requirements of the existing Boric Acid Wastage Surveillance Program. Leakage is detected by steam discharge, borated water, or other evidence of fluid escape. This is consistent with the applicant's commitments to NRC Bulletins 2001-01 and 2002-01.

The applicant stated that, in response to NRC Bulletin 2001-01, the industry will develop a follow-up examination plan for reactor vessel head penetrations. The schedule and frequency for follow up examinations will be determined based on the results of the initial examinations and the issuance of industry guidance to be provided by the Electric Power Research Institute (EPRI) MRP and the Nuclear Energy Institute (NEI). The visual inspections of the RVH and other RCS Alloy 600 components are performed in accordance with the Boric Acid Wastage Surveillance Program.

The applicant also stated that the comprehensive list of monitoring and trending activities discussed in the GALL Report for monitoring and trending PWSCC in Alloy 600 primary pressure boundary components include program activities that are contained in several separate AMPs 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). The staff has confirmed that the monitoring and trending attributes for the A600IP, when taken in context with the monitoring and trending attributes for the Chemistry Control, Boric Acid Wastage Surveillance, and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Programs, satisfy the recommendations of the GALL Report.

In its response to RAI 3.2.1-1, the applicant clarified, however, that commitments made by the applicant in response to NRC Bulletin 2002-02 and future inspection results could have an impact on the program, and the specific program attributes would be adjusted at that time. The applicant indicated that the St. Lucie Unit 1 and 2 FSAR supplements for the A600IP, provided in Appendix A1 Subsection 18.2.1 for Unit 1 and Appendix A2 Subsection 18.2.1 for Unit 2, will be revised to incorporate FPL commitments in response to the NRC communications referenced in previous paragraphs.

The staff is currently assessing whether visual examinations of PWR vessel heads are sufficient to detect cracking in the RVH penetration nozzles of PWR-designed plants and whether visual examination techniques can adequately manage initiation and growth of PWSCC in RVH penetration nozzle attachment welds. On November 21, 2002, the applicant submitted its 30-day supplemental response to NRC Bulletin 2002-02. In this response, the applicant provided the results of the applicant's visual and ultrasonic examinations that were performed on the St. Lucie Unit 1 RVH head. The applicant's response of November 21, 2002, also included the responses to staff requests communicated to the applicant in a series of teleconference calls during the period of October 10–14, 2002. These teleconference calls are documented in an NRC teleconference summary dated November 13, 2002.[1] The staff is currently reviewing the applicant's responses to NRC Bulletin 2002-01 (FPL letters L-2002-061 and L-2002-116 dated April 2, 2002, and June 27, 2002, respectively) and Bulletin 2002-02 (FPL letter L-2002-185 dated September 11, 2002). The staff is currently in the process of determining whether additional augmented inspection requirements are necessary for Class 1 nickel-based alloy components in the industry's nuclear power plants, including those at the St. Lucie station. To ensure that the applicant's A600IP will be current with the CLB for the St. Lucie units, the staff requests that FPL commit to implementing any inspection methods, inspection frequencies, and acceptance criteria that are recommended by the industry and approved by the NRC, as well as any further requirements that may result from the staff's resolution of the issue of PWSCC in Class 1 nickel-based alloy components. In addition, since Bulletins 2001-01 and 2002-02 are specific to the resolution of degradation that occurs in RVHs and their associated penetration nozzles and attachment welds, the staff requests additional discussion and clarification of the inspections methods that will be used for the nickel-based alloy components in the remaining RCS Class 1 subsystems (such as those in the St. Lucie pressurizers, steam generators, hot legs, and reactor vessel internals). These issues are characterized in open items 3.1.0.1-1 and 3.1.0.1-2.

Acceptance Criteria: The applicant states that 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, before implementing any corrective action. The applicant does not define the acceptance criteria for partial through-wall flaws identified and sized by volumetric inspection methods or identified by surface examination methods and sized by volumetric examination methods. As a minimum, the applicant is required by 10 CFR 50.55a to comply with the flaw acceptance criteria specified for ASME Class 1 components in the ASME Code, Section XI, Articles IWA-3000 and IWB-3000, regardless of whether the material is fabricated from Alloy 600. Alternative acceptance criteria for partial through-wall flaws may be used by the applicant if covered within the scope of a relief request that is submitted and approved by the staff pursuant to 10 CFR 50.55a(a)(3).

The staff is aware that the PWR industry organizations, such as NEI and EPRI's Integrated Task Group on Alloy 600, are in the process of performing detailed industry studies on cracking of Alloy 600 base metal components and Alloy 82/182 weld metal components. For the Class 1 Alloy 600 components within the scope of the applicant's A600IP, the results of these industry initiatives may include recommendations for implementing alternative acceptance criteria to those required by Section XI of the ASME Code. The applicant's acceptance criteria program attribute for the A600IP implies that the applicant will be using alternative acceptance criteria for partial through-wall flaws that are detected in the Class 1 Alloy 600 components within the scope of the A600IP. The applicant may use alternative acceptance criteria developed either by the applicant or the industry for partial through-wall flaws if the alternative criteria have been submitted to and accepted by the staff pursuant to 10 CFR 50.55a(a)(3). However, the

1 Letter from B.T. Moroney (NRC) to Florida Power and Light Company, "Summary of Conference Calls with Florida Power and Light Regarding Reactor Vessel Head Inspection Results (TAC No. MB5917)," November 13, 2002.

applicant did not specify what the acceptance criteria will be for partial through-wall flaws that may occur in the Class 1 Alloy 600 components. A commitment made by the applicant in response to Open Item 3.1.0.1-1 will resolve this issue because any acceptance criteria for partial through-wall flaws will have to be reviewed by the NRC and found to be acceptable.

The applicant's acceptance criterion for the visual inspections (i.e., for through-wall flaws resulting in leakage of the primary coolant) is no pressure boundary leakage. This acceptance criterion for performing visual inspections of the Class 1 Alloy 600 RCS components is acceptable to the staff because it complies with the "no RCS pressure boundary leakage" requirement specified in the St. Lucie technical specifications.

Operating Experience: The applicant states that it has been an active participant in the Combustion Engineering Owners Group (CEOG), EPRI, and NEI initiatives regarding cracking of Alloy 600 RCS components and that the A600IP was created in response to NRC Generic Letter 97-01 and updated in response to NRC Bulletin 2001-01. The applicant states that the A600IP has proven experience in addressing the concerns and requirements of the generic letter and the bulletin and that, to date, it has performed visual inspections on the top of the Units 1 and 2 RVHs 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. However, in the response to RAI 3.2.1-1, the applicant also indicated that the scope and results of ISI examinations and augmented examinations performed to date on the St. Lucie Units 1 and 2 RVHs are summarized in its responses to NRC Bulletins 2002-01 and 2002-02 and that the results of the visual examinations performed to date do not have an impact on the program attributes for the A600IP. The staff's assessment of the implications that NRC Bulletins 2002-01 and 2002-02, and the applicant's responses to these Bulletins, have on the "Detecting of Aging Effects" and "Monitoring and Trending" program attributes has been assessed in previous paragraphs.

The applicant indicated that visual inspections performed at St. Lucie Units 1 and 2 have identified leakage of Alloy 600 pressurizer and Class 1 piping instrument nozzles. In all cases, the leaking nozzles have been removed and replaced in accordance with the requirements of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The applicant indicated that the visual inspections provided timely detection and repair of RCS pressure boundary leakage. The applicant's time limited aging analysis associated with these repairs (half nozzle repair methods) address management of this degradation and is discussed in Section 4.6.4 of the LRA. The staff evaluates this TLAA in Section 4.6.4 of this SER.

The staff is currently addressing the generic implications of the V.C. Summer hot-leg nozzle safe-end weld cracking event (which was summarized earlier in this section) with the U.S. nuclear industry owners groups, research organizations, and licensees to determine which inspection methods will be necessary for Class 1 safe-end welds fabricated from Alloy 82/182. The staff considers this operating issue to be outside the scope of license renewal. However, a commitment made by the applicant in response to Open Item 3.1.0.1-1 will provide assurance that the A600IP will be updated to incorporate any new inspection requirements that may result from the staff's resolution of the V. C. Summer issue.

3.1.0.1.3 FSAR Supplement

The applicant’s FSAR supplements for the A600IP are provided in Section 18.2.1 of Appendix A1 to the LRA for Unit 1 and Section A2 of the LRA for Unit 2. These FSAR supplements provide an overview of the program as described in Section B.3.2.1 of Appendix B to the application. In its response to RAI B.3.2.1, dated September 26, 2002, the applicant stated that the A600IP will be revised to incorporate FPL commitments in response to the NRC communications referenced in the previous paragraphs. This reflects the applicant’s response to RAI B.3.2.1-1 and provides assurance that the applicant will modify the A600IP based on the applicant’s commitments made in past and future responses to NRC Bulletins 2001-01, 2002-01, and 2002-02. However, the applicant will need to revise its FSAR supplement summary descriptions for the A600IP to reflect the applicant’s responses to open items 3.1.0.1-1 and 3.1.0.1-2. This is characterized as confirmatory item 3.1.0.1-1.

3.1.0.1.4 Conclusion

The staff has reviewed the information provided in Section B.3.2.1 of Appendix B to the LRA, as supplemented by the applicant’s response to RAI B.3.2.1-1. On the basis of this review, with the exception of open items 3.1.0.1-1 and 3.1.0.1-2, the staff concludes that the applicant has demonstrated that the effects of aging associated with Alloy 600 Class 1 components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.2 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program

3.1.0.2.1 Summary of Technical Information in the Application

In Section 3.1.6. of Appendix B to the LRA, the applicant identifies that aging management of RCS components made from cast austenitic stainless steels (CASS) will be managed by the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (henceforth identified as the CASS Program).

The applicant states that the CASS Program is designed to identify those CASS components that are susceptible to thermal aging embrittlement and to monitor these components for the effects of thermal aging embrittlement on the fracture toughness properties. For those CASS components that the program identifies as being potentially susceptible to thermal aging, the program specifies either enhanced implementation of volumetric examinations for the detection and sizing of cracks in the components, or implementation of plant-specific or component-specific flaw tolerance evaluations for the CASS materials.

The applicant states that the CASS Program is consistent with the 10 program attributes of Aging Management Program XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” as specified in NUREG-1801, Volume 2, “Generic Aging Lessons Learned (GALL) Report, Tabulation of Results,” dated July 2001. The applicant also states that commitment dates associated with implementation of this AMP are contained in Appendix A of the LRA.

3.1.0.2.2 Staff Evaluation

The 10 program attributes in GALL AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage thermal aging and hence loss of fracture toughness properties in RCS components made from CASS. The program attributes for GALL AMP XI.M12 are in accordance with the staff’s position on evaluation of CASS materials, as given in the Interim Staff Guidance on CASS dated May 19, 2000. In Section 3.1.6 of Appendix B to the LRA, the applicant states that the program attributes for the CASS Program are consistent with those specified in AMP XI.M12 of the GALL Report. The applicant retains the program description of the CASS Program as well as the descriptions of the program’s 10 attributes, on record at the St. Lucie Nuclear Station.

The staff inspected the CASS Program for acceptability and compared the program’s 10 attributes to the 10 attributes described in GALL AMP XI.M12. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff’s review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the FSAR supplements’ descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.1.0.2.3 FSAR Supplement

In Section 18.1.6 of Appendix A1 to the LRA (i.e., the FSAR supplement summary description for AMPs), the applicant stated that the CASS Program will include a determination of the susceptibility of Class 1 CASS piping components to thermal aging embrittlement and will provide for the subsequent aging management of those components that have been identified as being potentially susceptible. The applicant also stated that aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation, and that the program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1. The applicant’s FSAR supplement summary description for the CASS Program reflects the need to implement the program prior to entering the periods of extended operation. With the exception of confirmatory item 3.0.2.2-1, the staff does not see the need for changes to the FSAR supplement descriptions for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program.

3.1.0.2.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant’s claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.1.0.3 Small Bore Class 1 Piping Inspection Aging Management Program

The applicant credits the Small Bore Class 1 Piping Inspection with managing aging effects in small bore Class 1 piping. The applicant describes this program in Section 3.1.5 of Appendix B to the LRA. Although one-time small bore piping inspection programs for RCS piping and feedwater piping are addressed in the GALL Report Section X1.M32, the applicant describes the program in terms of how the Small Bore Class 1 Piping Inspection meets the 10 program elements stated in the Standard Review Plan for License Renewal (NUREG-1800). The applicant's descriptions of the 10 program attributes for the Small Bore Piping Inspection are provided in detail in Section 3.1.5 of Appendix B to the LRA.

3.1.0.3.1 Summary of Technical Information in the Application

The applicant states that the Small Bore Class 1 Piping Inspection will occur in the latter part of the initial operating period for St. Lucie Units 1 and 2. The timing of this inspection was established to maximize the operating time and, thus susceptibility to any age-related cracking mechanisms. This program is plant specific. The applicant indicates that it will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to the implementation of this inspection. The applicant states that commitment dates associated with the implementation of this new program are contained in the FSAR supplement for the program provided in Appendix A of the LRA.

In Section 3.1.5 of Appendix B to the LRA, the applicant summarizes the ability of the Small Bore Class 1 Piping Inspection to manage age-related cracking in the Class 1 small bore piping by discussing the seven program attributes for the program consistent with program attributes recommended by the SRP-LR.

3.1.0.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.5 of Appendix B to the LRA regarding the applicant's demonstration of the small bore Class 1 piping inspection to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to AMR. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The small bore Class 1 piping inspection is a one-time inspection of a sample of Class 1 piping less than 4 inches in diameter. The applicant states that the sample of welds to be examined will be selected by using a risk-informed approach. The staff is therefore concerned that the risk-informed methods discussed in the LRA's description of the Small Bore Piping Inspection (Section 3.1.5 of Appendix B to the LRA) may be used as a basis for eliminating the volumetric examinations of small-bore Class 1 piping (less than 4 inches nominal pipe size [NPS]) joined by full-penetration butt welds. The staff addresses this concern later in its evaluation of the Detection of Aging and Monitoring and Trending program attributes for the AMP.

Commitment dates associated with the implementation of this new program are provided in Section 18.1.5 of Appendix A to the LRA. The staff agrees with the adequacy of the applicant's description of the scope of this program because the program focuses on implementation of an inspection of small bore Class 1 piping that uses volumetric examination techniques that have been demonstrated to be acceptable for detecting cracking in the components.

Preventive or Mitigative Actions: The applicant states that no preventive actions are applicable to this AMP. The staff agrees that an inspection-based program is designed to detect age-related cracking in the St. Lucie small bore Class 1 piping, and is on a preventive/mitigative program that is designed to preclude the occurrence of cracking.

Parameters Monitored or Inspected: Section 3.1.5 of Appendix B to the LRA states that cracking is the parameter that the Small Bore Class 1 Piping Inspection monitors. The staff has raised the issue of degradation in Small Bore Class 1 piping because it was concerned that current ASME Section XI surface examination requirements for inspecting full-penetration butt welds in small bore Class 1 piping may not be sufficient to detect cracking that is induced by either thermal fatigue or stress corrosion. The staff concurs with the applicant's aging effect parameter for this AMP and concludes that the Parameters Monitored or Inspected program attribute is acceptable.

Detection of Aging Effects and Monitoring and Trending: The applicant states that the volumetric technique chosen will permit detection and sizing of significant cracking of small bore Class 1 piping. The staff agrees with the adequacy of the examination technique described by the applicant because this is a proven method for this type of inspection. The applicant also states that the detection of cracking will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing (UT) or radiography testing. The staff agrees with the adequacy of the examination technique described by the applicant because volumetric inspection techniques, such as UT or radiology testing, have been demonstrated to be acceptable methods of detecting cracks in ASME Code Class components.

The applicant states that this is a one-time inspection, and as such, no monitoring and trending are anticipated. The risk-informed approach used for the AMP consists of two essential elements—(1) a degradation mechanism evaluation to assess the failure potential of the piping system under consideration, and (2) a consequence evaluation to assess the impact on plant safety in the event of a piping failure. In RAI B.3.1.5-1, the staff asked the applicant to—

- Discuss which mechanisms will be used to determine the greatest potential failure susceptibility locations and discuss how the worst-case consequence locations for the small bore piping will be determined. Discuss how these two essential risk-informed elements will be used to quantify the susceptibility rankings of the small bore Class 1 piping within the scope of the Small Bore Class 1 Piping Inspection.

- Explain which documents or information will be used to define the sample size for the volumetric inspections that will be proposed for the small bore Class 1 piping.

In response to RAI B.3.1.5-1, dated September 26, 2002, the applicant stated that the Small Bore Class 1 Piping Inspection will occur in the latter part of the initial operating periods for St. Lucie, Units 1 and 2. The applicant states that the timing of the inspection was established to maximize the operating time and, thus, the susceptibility to any age-related cracking mechanism. The inspection will incorporate the results and recommendations from industry initiatives, including applicable results from the EPRI industry initiative assembling previous guidance on nondestructive examination (NDE) methodologies and providing recommendations for specific NDE technology and variables for examination methods selected for the Small Bore Class 1 Piping Inspection. The staff concludes that this approach is reasonable and is therefore acceptable.

In response to RAI B.3.1.5-1, the applicant stated that, as indicated in LRA Sections 18.1.5 of the FSAR supplements and Section 3.1.5 of Appendix B to the LRA will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to its implementation. The report will include a description of the methodologies used to determine the greatest potential failure susceptibility locations and worst-case consequence (risk-informed) small bore Class 1 piping locations. The applicant also indicated that the report will describe the methods used to determine the sample size for the volumetric examinations proposed for the small bore Class 1 piping.

The applicant has not yet submitted the Small Bore Class 1 Piping Inspection plan to the staff for review because the applicant has not yet implemented the risk-informed methodologies for determining the small bore piping locations most susceptible to age-related cracking and for establishing the sample size for the inspection. However, the staff confirmed that the applicant has included statements in Sections 18.1.5 of the FSAR supplements of the LRA, that commit the applicant to submitting the Small Bore Class 1 Piping Inspection plan before the end of the operating term, including the risk-informed methodologies for determining the sample locations and sample size for the inspections, to the NRC for review and approval.

The staff has approved risk-informed inservice inspection (RI-ISI) methods for ASME Code Class components through the relief request process for approving acceptable alternatives to the requirements of Section XI to the ASME Boiler and Pressure Vessel Code, as allowed under the provisions of 10 CFR 50.55a(a)(3)(i). However, the license renewal rule does not allow the staff to accept the elimination of SCs from aging management reviews based on risk-informed arguments. The application does not provide a clear indication whether the risked-informed methods within the scope of the Small Bore Class 1 Piping Inspection Plan are methods within the scope of a RI-ISI program that are required to be submitted for review and approval under the provisions of 10 CFR 50.55a(a)(3) or simply a risk-informed susceptibility approach that will be used to establish the small bore Class 1 piping locations for volumetric examination in each unit. The staff raised the issue on small bore piping because it was concerned that current ASME Section XI surface examination requirements for small bore Class 1 piping (less than 4 inches Nominal Pine Size) joined by full-penetration butt welds may not be sufficient to detect cracking that initiates in the welds as a result of thermal fatigue or stress corrosion. The staff has the following concern if the risk-informed methods within the scope of the Small Bore Class 1 Piping Inspection AMP are part of a RI-ISI program that would be required to be approved under the provisions of 10 CFR 50.55a(a)(3):

- The potential exists for RI-ISI methodologies to “screen out” the volumetric examinations of the small bore piping based on risk information, and therefore if the risk-informed methods are part of a RI-ISI program, they may be used to eliminate all of the volumetric examinations proposed for the small bore Class 1 piping components.

The applicant needs to resolve this issue. This issue is characterized as open item 3.1.0.3-1.

Acceptance Criteria: The applicant states that any cracks identified will be evaluated and, if appropriate, entered into the corrective action program. The applicant also states that the evaluation of the inspection results may result in additional examinations consistent with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff finds this approach acceptable because industry standards will be used in the acceptance criteria.

Operating Experience: The applicant describes this one-time inspection as a new activity, which will use techniques with demonstrated capability and a proven industry record to detect piping weld and base material flaws. Effective and proven volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel. Results and recommendations from industry initiatives will be incorporated into the inspection. The staff finds this approach acceptable because cracking of small bore piping has not been prevalent in the industry and a one-time inspection program is adequate based on the lack of industry experience to date.

3.1.0.3.3 FSAR Supplement

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

The staff considers the risk-informed program for the small bore Class 1 piping to be an alternative to the ISI requirements of Section XI of the ASME Boiler and Pressure Vessel Code for ASME Code Class 1 components. Submittal of this program is required to be done under the provisions of 10 CFR 50.55a(a)(3) for approval of alternatives to Section XI of the ASME Boiler and Pressure Vessel Code. The applicant needs to provide additional information as to how risk-informed methods for the Small Bore Class 1 Piping Inspection will be sufficient to detect and trend for cracking in the small bore Class 1 components to ensure the integrity of these components through the extended periods of operation for the units. Therefore, the applicant will need to revise its FSAR supplement summary description for the Small Bore Class 1 Piping Inspection and to reflect the applicant’s response to open item 3.1.0.3-1. This is characterized as confirmatory item 3.1.0.3-1.

3.1.0.3.4 Conclusion

The staff has reviewed the information provided in Section 3.1.5 of Appendix B to the LRA, as supplemented by the applicant’s response to RAI B.3.1.5-1, dated September 26, 2002. On the basis of this review, as set forth above, with the exception of open item 3.1.0.3-1, the staff concludes that the effects of aging associated with small bore Class 1 piping components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.4 Steam Generator Integrity Program

3.1.0.4.1 Summary of Technical Information in the Application

In Section 3.1.6. of the LRA, the applicant identifies that aging management of steam generator tubes will be managed by the Steam Generator Integrity Program which is discussed in Section 3.2.13 of Appendix B to the LRA.

The applicant states that the Steam Generator Integrity Program is consistent with the 10 attributes of the aging management program in the GALL Report, XI.M19, “Steam Generator Tube Integrity.” In addition, the program scope includes the Unit 2 steam generator tube support lattice bars. The Steam Generator Integrity Program also credits sludge lancing as a preventive action for secondary-side steam generator tube degradation and tube bundle flushing to minimize flow-accelerated corrosion of the Unit 2 carbon steel tube support lattice bars.

The applicant states that the Steam Generator Integrity Program Steam Generator Integrity Program has been effective in ensuring detection of the aging effects of cracking and loss of material in steam generator tubes. The program is structured to meet NEI 97-06, “Steam Generator Program Guidelines,” which references several EPRI guidelines. These EPRI guidelines include steam generator examination, tube integrity assessments, primary and secondary water chemistry, primary-to-secondary leakage, in-situ pressure testing, and tube plug assessment. Although the applicant did not explicitly discuss this in the LRA, the Steam Generator Integrity Program must also satisfy the steam generator surveillance requirements in the St. Lucie Units 1 and 2 technical specifications.

3.1.0.4.2 Staff Evaluation

The staff reviewed the Steam Generator Integrity Program to determine whether the applicant has demonstrated that the effects of aging on the steam generator components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). The 10 program elements in the GALL Report, AMP XI.M19, “Steam Generator Tube Integrity,” provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects on steam generator components.

The applicant evaluated the current steam generator inspection activities against industry recommendations provided by EPRI via NEI 97-06 and the steam generator suppliers. The applicant states that the effectiveness of the program is demonstrated by the operating experience and inspection results. The Steam Generator Integrity Program provides assurance that tube wear, pitting corrosion, general corrosion, crevice corrosion, PWSCC, IGA, and IGSCC of components are managed and that the intended functions of the steam generators will be maintained consistent with the CLB during the period of extended operation. The applicant retains the program description of the Steam Generator Integrity Program and the descriptions of the program’s 10 elements on record at the St. Lucie nuclear station.

The staff inspected the Steam Generator Integrity Program for acceptability and compared the program’s 10 elements to the 10 elements described in the GALL Report, XI.M19. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff’s review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M1 in the FSAR Supplements' descriptions of this AMP. This is confirmatory item 3.0.2.2-1.

3.1.0.4.3 FSAR Supplement

The staff reviewed Section 18.2.13 of Appendix A1 and Section 18.2.12 of Appendix A2 of the FSAR supplement of the LRA. Pending completion of confirmatory item 3.0.2.2-1, the staff concluded that the information provided in the FSAR supplements for aging management of steam generators discussed above is equivalent to the information in Table 3.1-2 of NUREG-1800, and, therefore, provides an adequate summary of the program activities required by 10 CFR 54.21(d).

3.1.0.4.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.1.0.5 Reactor Vessel Integrity Program

The applicant credits the Reactor Vessel Integrity Program (Section 3.2.12 of Appendix B to the LRA) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. The staff's review of this AMP is provided below.

The applicant described its Reactor Vessel Integrity Program in Section 3.2.12 of Appendix B to the LRA. The St. Lucie Units 1 and 2 Reactor Vessel Integrity Program is designed to manage RV irradiation embrittlement and encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure/Temperature Limit Curves

These aging management subprograms support the applicant's RV neutron embrittlement TLAA (Section 4.2.1 of the LRA), which includes analyses of the upper-shelf energy, USE pressurized thermal shock (PTS), and pressure-temperature (P-T) limits. The staff's evaluation of this TLAA is provided in Section 4.2 of this SER.

Criteria of the first 40 years are specified in 10 CFR Part 50, Appendix H, "Reactor Vessel Materials Surveillance Program Requirements," which concerns monitoring changes in the fracture toughness of ferritic materials in the reactor beltline region caused by exposure to neutron irradiation and thermal environments. Appendix H requires that the surveillance program design and withdrawal schedule meets the requirements of American Society for Testing and Materials (ASTM E 185), “Standard Practice for Conducting Surveillance Tests for Light-Water-Cooled Nuclear Power Vessels.”

Revision 2 of RG 1.99, “Radiation Embrittlement of Reactor Vessel Materials,” describes general procedures acceptable to the NRC staff for calculating the effects of neutron irradiation embrittlement of the low-alloy steels used for light-water-cooled RVs. Surveillance data from the Appendix H program are used in RG 1.99, Revision 2, calculations, if applicable. The four subprograms are reviewed separately in the following paragraphs.

3.1.0.5.1 Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram

Summary of Technical Information in the Application. The applicant described the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram in Appendix B, Section 3.2.12.1, of the LRA. The staff reviewed the subprogram to determine whether the applicant has demonstrated that the aging effects covered by the subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff’s evaluation of the applicant’s Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Reactor Vessel Integrity Program includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of the test program for these materials involves the measurement of irradiation effects by pre-irradiation and post-irradiation testing of Charpy V-notch and tensile samples. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore, acceptable to the staff.

Preventive or Mitigative Actions: No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation of the RV. The Reactor Vessel Integrity Program is a surveillance monitoring program designed to monitor for property changes in materials and for loss of fracture toughness in the materials used to fabricate the RVs and to comply with the reactor vessel material surveillance program capsule withdrawal and testing requirements of 10 CFR Part 50, Appendix H. The program uses Charpy V impact testing of the surveillance capsule specimens to monitor changes (losses) in fracture toughness in the RV beltline materials. Surveillance programs implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, are not designed to prevent or mitigate aging effects before their occurrence. The staff, therefore, concludes that no preventive actions are needed. The staff finds this acceptable because the program is not designed to be a preventive or mitigative program for precluding aging effects prior to their occurrence.

Parameters Monitored or Inspected: The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram monitors reduction of fracture toughness and tensile strength, as measured by Charpy V-notch and tensile test results for irradiated specimens for reactor vessel plate and weld materials. Additionally, accumulated neutron fluence is monitored utilizing surveillance capsule dosimetry. Tables 5.4-3 and 5.3-9 of Appendices A1 and A2 of the LRA, include the changes to the surveillance capsule schedules for Units 1 and 2 to address the extended period of operation.

In regards to the surveillance capsule removal schedule, the applicant indicates that the fourth capsule in Unit 1 will be withdrawn at 38 effective full power years (EFPY) with a predicted neutron fluence of 4.4 x 10 19 neutrons per square centimeter (n/cm). In Table 4.2-3 of the LRA, the applicant indicates that the peak end of life (EOL) fluence for Unit 1 is 4.68 x 10 19 n/cm, which is greater than the predicted fluence to be received on the fourth capsule for Unit 1. For Unit 2, the applicant indicates that the fourth capsule will be withdrawn at 44 EFPY with a predicted neutron fluence of 4.56 x 10 19 n/cm. In Table 4.2-4 of the LRA, the applicant indicates that the peak EOL fluence for Unit 2 is 4.89 x 10 19 n/cm, which is also greater than the predicted fluence to be received on the fourth capsule for St. Lucie Unit 2.

In accordance with ASTM E185, for current 40-year practice, it is recommended that the last capsule to be removed should receive the same or higher fluence than the peak EOL fluence. Therefore, the applicant should provide updated capsule removal schedules that reflect a capsule to be withdrawn with a predicted fluence equal to or greater than the peak EOL fluence for the extended period of operation Units 1 and 2. This is open item 3.1.0.5-1.

Detection of Aging Effects: The applicant states that the effects of aging will be detected based on the data obtained in the monitoring and trending effort from the RV material surveillance program. The will be done by quantifying the change in temperature at 30 ft-lb energy from unirradiated and irradiated specimens. The staff finds this approach to be acceptable since it will determine the increase in reference temperature due to irradiation, and it is in accordance with the requirements of 10 CFR Part 50, Appendix H.

Acceptance Criteria: The acceptance criteria for fracture toughness are that the reference temperature for PTS, (RT pts), must be below the screening criterion of 270 °F for plates, forgings, and longitudinal welds, and below 300 °F for circumferential welds. The staff finds this approach acceptance since it complies with the requirements of the PTS rule stated in 10 CFR 50.61. The acceptance criterion for Charpy Upper Shelf Energy (USE) is that the USE remains above 50 ft-lbs. For materials whose Charpy USE that fall below 50 ft-lbs, there are provisions in Appendix G to 10 CFR Part 50 that must be followed. Specifically, the applicant must demonstrate that during the period of extended operation the Charphy USE has a margin of safety against fracture equivalent to that specified in Section XI of the ASME Boiler and Pressure Vessel Code. The staff finds this acceptable because it complies with the Requirements stated in 10 CFR Part 50, Appendix G.

Operating Experience: The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram meets the requirements stated in 10 CFR Part 50, Appendix H, and has been in effect since initial plant startup. The applicant has updated this program over the years and has gained experience in addressing reduction in fracture toughness. The applicant updates the Units 1 and 2 P-T limit curves using the results from the vessel surveillance capsule specimen evaluations. The applicant evaluated the Units 1 and 2 RT pts values that are below the screening criteria in 10 CFR 50.61. Also, the applicant evaluated to the USE values that remain above 50 ft-lbs, which is in accordance with 10 CFR Part 50, Appendix G. Therefore, the staff finds the applicant's description of operating experience acceptable.

FSAR Supplement. In Section 18.2.12.1 of Appendix A1 and Section 18.2.11.1 of Appendix A2 of the LRA, the applicant descries the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprograms for Units 1 and 2. The subprogram descriptions are consistent with the material contained Section 3.2.12.1 of the Appendix B and are therefore acceptable to the staff. However, as indicated in open item 3.1.0.5-1, the applicant should update its capsule removal schedules in Tables 5.4-3 and 5.3-9 of Appendices A1 and A2 of the FSAR supplement, for Units 1 and 2, respectively.

Conclusion. The staff has reviewed the information provided in Section 3.2.12.1 of Appendix B of the LRA and the summary description of the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram in Section 18.2.12.1 of Appendix A1 and Section 18.2.11.1 of Appendix A2 of the FSAR supplement for Units 1 and 2, respectively. On the basis of ITS review of the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram, with the exception of open item 3.1.0.5-1, the staff finds that the continued implementation of this AMP provides reasonable assurance that the reduction in fracture toughness of RV beltline region materials will be adequately managed, such that the intended functions of the RV will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR Part 54.21(a)(3).

3.1.0.5.2 Fluence and Uncertainty Calculations Subprogram

Summary of Technical Information in the Application. The applicant described the Fluence and Uncertainty Calculation Subprogram in Appendix B, Section 3.2.12.2, of the LRA. The staff reviewed the subprogram to determine whether the applicant demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicates that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Fluence and Uncertainty Calculations Subprogram includes the belt line materials defined in 10 CFR 50.61(a)(3). The scope of this subprogram for these materials involves calculations to provide accurate predictions of the actual reactor vessel neutron fast fluence values for use in the development of the P-T limit curves and PTS calculations. This is consistent with the scope of the RV integrity programs required to be implemented in accordance with the requirements stated in 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

Preventive or Mitigative Actions: There are no preventive or mitigative actions associated with the Fluence and Uncertainty Calculations Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: The monitored parameters are the reactor vessel neutron fast fluence values, which are predicted based on analytical models meeting the requirements of draft NRC RG DG-1053, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” which is consistent with RG 1.190. The monitored parameters are benchmarked using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. Benchmarking has been supplemented by draft RG DG-1053 cavity dosimetry. The applicant indicates that the determination of fluence is based on both calculations and measurements. The applicant’s methodology includes calculating fluence predictions and qualifying the calculational methodology by actual fluence measurements.

The applicant has implemented a pressure vessel radiation surveillance program at Units 1 and 2, as discussed above. The program is based on ASTM E185. Six material test capsules were placed in each unit. The program provides for the periodic removal of capsules for evaluation throughout the plant life. The present database at St. Lucie includes data evaluated from three Unit 1 capsules and two Unit 2 capsules. The results from these measurements, the Units 1 and 2 operating histories, and calculated power distributions make up the database for the fluence calculations.

The most recent data calculations use discrete ordinates radiation transport for the neutron transport calculation, a Discreet Ordinates Radiation Transport post-processor code named DOTSOR for geometry conversion, and Bugle-96. The power distributions are based on the Westinghouse Advanced Nodal Code. The staff finds the applicant’s fluence calculation methodology acceptable since it is consistent with the recommendations of DG-1053 and RG 1.190.

Detection of Aging Effects: Fluence values are determined by actual calculations of vessel fluence, empirical results from Charpy V-notch tests of irradiated specimens, and capsule dosimetry in accordance with the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. The staff finds this approach to be acceptable since these parameters are sufficient for determining predicting fluence values.

Monitoring and Trending: Neutron fluence and uncertainty calculations are performed to predict the fast neutron fluence. These calculations are verified using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. The staff finds this approach acceptable since dosimetry results can be used to verify calculations to predict neutron fluence.

Acceptance Criteria: Based on the calculations, the reactor vessel fluence uncertainty values are to be within 20 percent. Calculated fluence values for fast neutrons (above 1 MeV) are compared with measured values. This methodology represents a continuous validation process to ensure that no biases have been introduced and that the uncertainties remain comparable to the reference benchmarks. The staff finds this approach to be acceptable because it is consistent with DG-1053 and RG 1.190.

Operating Experience: The applicant performed neutron fluence and uncertainty calculations for Units 1 and 2 in accordance with the guidelines of DG-1053 and validated the results using data obtained from capsule dosimetry. Since the calculated fluence values were compared to measured values, the staff finds that the applicant’s description of operating experience supports the attributes of the subprogram described above.

FSAR Supplement. Section 18.2.12.2 of Appendix A1 and Section 18.2.11.2 of Appendix A2 of the LRA provide the applicant's Description of the Fluence and Uncertainty Calculations Subprograms at Units 1 and 2. The subprogram descriptions are consistent with the material contained in Section 3.2.12.2 of Appendix B and are therefore acceptable to the staff.

Conclusion. The staff has reviewed the information provided in Section 3.2.12.2 of Appendix B of the LRA, and the summary description of the Fluence and Uncertainty Calculations Subprogram in Section 18.2.12.2 of Appendix A1 and Section 18.2.11.2 of Appendix A2 of the FSAR supplements for Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Fluence and Uncertainty Calculations Subprogram, such that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.3 Monitoring Effective Full Power Years Subprogram

Summary of Technical Information in the Application. The applicant described the Monitoring Effective Full Power Years Subprogram in Appendix B, Section 3.2.12.3, of the LRA. The staff reviewed the subprogram in Appendix B, Section 3.2.12.3, of the LRA to determine whether the applicant has demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Monitoring Effective Full Power Years Subprogram includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of this program is to accurately monitor and tabulate the accumulated operating time experienced by the RV and to ensure that the P-T limit curves. The scope of this program supports the requirements of 10 CFR Part 50, Appendix G, and is therefore acceptable to the staff.

Preventive or Mitigative Actions: There are no preventive or mitigative actions associated with the Monitoring Effective Full Power Years Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: This subprogram monitors and tabulates the accumulated operating time experienced by St. Lucie Units 1 and 2 RVs. The EFPY of plant operation are based on core thermal power. EFPY values are derived by accumulating time at the measured thermal power relative to rated thermal power. The staff finds this approach to be acceptable since it uses appropriate plant parameters to calculate EFPY of operation.

Detection of Aging Effects: EFPY calculations are utilized for the prediction of fast neutron fluence and the determination of the reduction of fracture toughness of RV critical materials. The staff finds this approach to be acceptable since it supports the requirements of 10 CFR Part 50, Appendix G.

Monitoring and Trending: This subprogram monitors the RV EFPY to be used in predicting the fast neutron fluence. Each St. Lucie unit is monitored to determine the EFPY of operation. These data are used to validate the applicability of the P-T limit curves for the next operating cycle. The staff finds this approach to be acceptable since it supports the requirements of 10 CFR Part 50, Appendix G.

Acceptance Criteria: Calculated EFPY shall not exceed the technical specification limits for the validity of the P-T limit curves. The staff finds this acceptable since it is consistent with the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

Operating Experience: The EFPY calculations are used to verify the continued validity of the P-T limit curves. Plant-specific experience has proven this an effective process to assure continued validity of the P-T limit curves. Therefore, the staff finds that the applicant's description of operating experience supports the attributes of the subprogram described above.

FSAR Supplement. Section 18.2.12.3 of Appendix A1 and Section 18.2.11.3 of Appendix A2 to the LRA provide the applicant's FSAR supplement for the Monitoring Effective Full Power Years Subprogram at St. Lucie Units 1 and 2, respectively. The subprogram descriptions are consistent with the material contained in Section 3.2.12.3 of Appendix B and are therefore acceptable to the staff.

Conclusion. The staff has reviewed the information provided in Section 3.2.12.3 of Appendix B of the LRA, and the summary description of the Monitoring Effective Full Power Years Subprogram in Section 18.2.12.3 of Appendix A1 and Section 18.2.11.3 of Appendix A2 of the FSAR supplement for St. Lucie Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Monitoring Effective Full Power Years Subprogram, such that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.4 Pressure-Temperature Limit Curves Program

Summary of Technical Information in the Application. The applicant described the Pressure-Temperature Limit Curves Subprogram in Appendix B, Section 3.2.12.4, of the LRA. The staff reviewed the subprogram in Appendix B, Section 3.2.12.4, of the LRA to determine whether the applicant has demonstrated that the aging effects covered by the subject subprogram will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Staff Evaluation. The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program, pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's Quality Assurance

Program is provided separately in Section 3.0.4 of this SER. This subprogram satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The scope of the Pressure-Temperature Limit Curves Subprogram includes all beltline materials, as defined in 10 CFR 50.61(a)(3). The scope of this subprogram is to establish P-T limit curves for the normal operating, inservice leak test, and hydrostatic test limits for the RCS, as applicable to the St. Lucie Units 1 and 2 pressure vessels. The curves are used to limit operations based on the material properties of the vessel caused by neutron irradiation. This is consistent with the scope of the Pressure-Temperature Limit Curves Subprogram, required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix G, and is therefore acceptable to the staff.

Preventive or Mitigative Actions: There are no preventive or mitigative actions associated with the Monitoring Effective Full Power Years Subprogram, nor did the staff identify a need for such actions.

Parameters Monitored or Inspected: P-T limit curves are generated assuming that a 1/4 Timeless (1/4T) surface flaw exists and using the fracture mechanics methodology in ASME Section XI, Appendix G. The P-T curves are determined by using bounding input heatup and cooldown transients. The staff finds this approach to be acceptable since the P-T limit curves are generated to meet the requirements in Appendix G to Section XI of the ASME Code, as required by Appendix G to 10 CFR Part 50.

Detection of Aging Effects: The P-T limit curves are not provided for the detection of aging effects, nor did the staff identify such a need. Rather, the P-T limit curves prevent or minimize the potential for damage to the RV materials.

Monitoring and Trending: The P-T limit curves are valid for a period expressed in EFPY in the technical specifications. These curves are updated prior to exceeding the EFPY for which they are valid. The time period for updating P-T limit curves may be adjusted if conditions such as changes in fuel type or fuel loading pattern occur. The staff finds this approach acceptable since the P-T limit curves are updated prior to exceeding the applicable EFPY, which is in accordance with the requirements of 10 CFR Part 50, Appendix G.

Acceptance Criteria: The P-T limit curves are valid for a specified number of EFPY. The curves must be updated before this time period is exceeded. The staff finds this approach acceptable since the validity of the curves is monitored, and the P-T limit curves are updated prior to exceeding the applicable EFPY, which is in accordance with the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

Operating Experience: FPL utilizes P-T limit curves for St. Lucie Units 1 and 2 that are updated using the results of data obtained from surveillance capsules. These curves are updated prior to exceeding the EFPY for which they are valid. The P-T limit curves provide sufficient operating margin, while preventing or minimizing the effects of reduced fracture toughness caused by neutron irradiation. Therefore, the staff finds that the applicant’s description of operating experience supports the attributes of the subprogram described above.

FSAR Supplement. Section 18.2.12.4 of Appendix A1 and Section 18.2.11.4 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the Pressure-Temperature Limit Curves Subprogram at St. Lucie Units 1 and 2, respectively. The subprogram descriptions are consistent with the material contained in Section 3.2.12.4 of Appendix B and are therefore acceptable to the staff.

Conclusion. The staff has reviewed the information provided in Section 3.2.12.4 of Appendix B of the LRA, and the summary description of the Pressure-Temperature Limit Curves Subprogram in Section 18.2.12.4 of Appendix A1 and Section 18.2.11.4 of Appendix A2 of the FSAR supplement for St. Lucie Units 1 and 2, respectively. On the basis of this review, the staff finds that the continued implementation of this AMP provides reasonable assurance that the aging effects associated with neutron irradiation embrittlement will be adequately managed by the Pressure-Temperature Limit Curves Subprogram, such that the intended functions of the RVs will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.5.5 Conclusion

With the exception of open item 3.1.0.5-1, pertaining to updated capsule withdrawal schedules to account for the peak EOL neutron fluence, the staff concludes that the applicant has demonstrated through the four subprograms of the Reactor Vessel Integrity Program that the aging effects associated with the RV components will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplement contains an appropriate summary description of the program activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.1.0.6 Fatigue Monitoring Program

The Fatigue Monitoring Program is described in Section 3.2.7 of Appendix B to the LRA. This aging management program provides for condition monitoring of components within several RCS systems that are within the scope of license renewal. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Fatigue Monitoring Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.6.1 Summary of Technical Information in the Application

Section 3.2.7 of Appendix B of the LRA describes the Fatigue Monitoring Program (FMP) as a plant-specific program that is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components remain within ASME Code, Section III fatigue limits. The applicant refers to the FMP as a confirmatory program rather than an actual aging management program because the program only monitors the number of significant plant transients to assure that number of transients assumed in the design fatigue analyses are not exceeded.

3.1.0.6.2 Staff Evaluation

The staff reviewed the FMP to determine whether it will assure that the fatigue design limits are not exceeded during the period of extended operation in accordance with the requirements in 10 CFR 54.21(a)(3). The staff evaluated the program against the following 10 elements that are described in Appendix A to NUREG 1800: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the program includes the reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and Class 1 reactor coolant system piping. The program tracks the number of design cycles to ensure that these components remain within their design limits. The staff considers the scope of the program, which includes the RCS components with ASME Code fatigue analyses, acceptable.

Preventive and Mitigative Actions: The applicant identified the cycle counting procedure as the preventative action for this program because, coupled with corrective actions, it prevents against exceeding the fatigue limits. The staff considers counting of design cycles to be an acceptable preventive action.

Parameters Inspected or Monitored: The parameters monitored are the cycles of design transients that cause significant fatigue usage in the Class 1 design analyses. The staff considers this monitoring appropriate because the program objective is to ensure the design analyses remain valid during the period of extended operation.

Detection of Aging Effects: The program monitors design transients that cause significant fatigue usage in the fatigue analysis of components and the information is used to assure that the fatigue design limits are not exceeded. This provides assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff considers this monitoring appropriate.

Monitoring and Trending: The applicant will use administrative procedures for logging design cycles. As stated previously, the program monitors the design transients that cause significant fatigue usage in the fatigue analysis of the components to assure that the fatigue analyses of record remain valid during the period of extended operation. The staff finds this program element acceptable

Acceptance Criteria: The applicant specified the maximum number of design cycles in the plant administrative procedures. The applicant indicates that the plant procedures require administrative action of the actual cycle count reaches 80% of any design cycle limit. The staff considers this criteria acceptable.

Operating Experience: The applicant's program involves tracking transients used in the design of these components. The applicant indicates that an independent assessment of the program was performed. According to the applicant the assessment concluded that the administrative procedure accurately identifies and classifies fatigue-sensitive design cycles. The staff finds the applicant has adequately addressed operating experience.

3.1.0.6.3 FSAR Supplement

The staff reviewed the summary description of the FMP provided in the FSAR supplements in Appendix A of the LRA. The staff determined that Appendix A to the LRA provides a sufficient summary description of the FMP to satisfy the requirements of 10 CFR 54.21(d).

3.1.0.6.4 Conclusion

The applicant references the FMP in its discussion of the fatigue TLAAs as a confirmatory program to assure that design fatigue limits are not exceeded during the period of extended operation. The staff considers the applicant’s program, which monitors the number of plant transients that cause significant fatigue usage in the Class 1 design analyses, an acceptable method to manage the fatigue usage of the RCS components within the scope of the program. The staff concludes that the FMP will adequately manage the thermal fatigue of RCS components at St. Lucie, Units 1 and 2, such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7 Reactor Vessel Internals Inspection Program

The applicant describes the reactor vessel internals inspection program in Section 3.1.4 of Appendix B to the LRA. The applicant credits this AMP to manage specific RV internals aging effects for Units 1 and 2. The staff reviewed the applicant’s description of the program to determine whether the applicant has demonstrated that it will adequately manage the applicable effects of aging in applicable RV internals during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7.1 Technical Information

The purpose of the reactor vessel internals inspection program is to monitor the condition of RV internals in order to assure that the applicable aging effects will not result in loss of intended functions during the period of extended operation. The applicant stated that different aging effects will affect various RV internals components. The aging effects addressed by this AMP include: (1) cracking, (2) reduction in fracture toughness, (3) loss of mechanical closure integrity, (4) and dimensional changes. The applicant stated that this AMP will supplement the chemistry control program and ISI program to assure that aging effects potentially requiring additional management will not result in loss of intended functions of the RV internals during the period of extended operation.

3.1.0.7.2 Staff Evaluation

The staff’s evaluations of seven of the program attributes are given in the paragraphs that follow. The staff’s evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the RV internals inspection program is documented in Section 3.0.4 of this SER.

Program Scope: The applicant stated that the scope of the RV internals inspection program consists of the following components: stainless steel upper guide structure support plate, fuel alignment plate, fuel alignment plate guide lugs, control element assemble (CEA) instrument tubes, CEA shroud base, incore instrumentation support plate and guide tubes, holddown ring, CEA extension shaft guides, fuel alignment plate guide lug inserts, core support barrel, core support barrel upper flange, alignment keys, and patches, core support plate, core shroud assemblies, fuel alignment pins, core support columns, CEA shroud bolts, fuel alignment plate guide lug bolts, and insert bolts, core shroud tie rods and snubber bolts, and cast austenitic stainless steel (CASS) flow bypass inserts, single tube CEA shrouds, and Unit 1 core support columns. The staff concludes that the applicant's scope for the RV internals program identified the appropriate RV internal components needing aging management by the program.

Preventive Actions: The applicant stated that there are no preventive/mitigative actions associated with this program, nor did the staff identify a need for such. The reactor vessel internals inspection program is a surveillance monitoring program and, as such, is not designed to prevent or mitigate the aging effects for the RV internals components prior to their occurrence. However, the staff noted that the applicant will control the reactor coolant water chemistry by the implementation of the chemistry control program.

Parameters Monitored or Inspected: The RV internals inspection program monitors cracking and reduction of fracture toughness on the reactor vessel internals accessible parts, and loss of mechanical closure integrity of RV internals bolted joints. In addition, visual inspections will also be performed to detect dimensional changes induced by void swelling.

The program requires the applicant to perform visual inspections of the RV internals components for the purpose of detecting loss of material due to wear or cracking initiated by fatigue, stress corrosion cracking (SCC) or irradiation assisted stress corrosion cracking (IASCC). The RV internals inspection requires the applicant to inspect CASS or highly irradiated stainless steel RV internals components for cracks to ensure that the components will not fail catastrophically as a result of fast fracture. In the case of the highly irradiated stainless steel RV internals components, visual inspections will also be used to detect dimensional changes induced by void swelling, as noted above.

The staff concludes that this attribute for the RV internals inspection program is acceptable because the program directly monitors for flaws (cracking and loss of material) that may occur in the RV internals components. The program also indirectly monitors for loss of mechanical closure integrity and dimensional changes that may occur in highly irradiated RV internals components.

Detection of Aging Effects: The aging effects of IASCC on selected reactor vessel internals parts will be detected by the performance of VT-1 examinations capable of detecting a 3/32 inch character against a grey background for the detection of cracks. Cracking is expected to initiate at the surface and will be detectable by the VT-1 visual examination.

Additionally, the applicant indicated that certain reactor vessel internals components that are fabricated from wrought stainless steel or CASS will be selected as leading locations for IASCC based on the highest projected combination of fluence and stress. For these reactor vessel internals 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. The staff finds this approach acceptable because enhanced VT-1 examinations are capable of detecting aging effects associated with IASCC.

Monitoring and Trending: The VT-1, and in some cases enhanced VT-1, examinations of selected 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 of operation, FPL plans to perform the first of these reactor vessel internals inspections early in the renewal period on St. Lucie Unit 1, since it is expected to be the unit leading in fluence at that time. Unless the Unit 1 inspection results dictate otherwise, the St. Lucie Unit 2 inspection will be conducted early in the second 10-year inspection interval in its license renewal term.

The applicant indicated that it has access to the EPRI Materials Reliability Project (MRP) products related to reactor vessel internals as they are completed. The MRP strategy is to evaluate potential aging mechanisms and their effects on specific reactor vessel internals components by evaluating parameters such as fluence, material properties, stress, etc. Critical locations can thereby be identified and tailored inspections can be conducted on either an integrated industry or plant-specific basis. With respect to dimensional changes due to void swelling, FPL indicated that as the void swelling “white paper” including available data and effects on RV internals is completed, FPL will evaluate the results and factor them into the RV internals inspection program, as applicable. In the LRA, the applicant commits to supplement the reactor vessel internals inspection program and to submit an integrated report to the NRC prior to the end of the initial operating term of St. Lucie Unit 1. The report will summarize the understanding of the aging effects applicable to the 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.

Acceptance Criteria: The applicant indicated that acceptance criteria will be developed prior to the visual examination. For RV internals components fabricated from CASS and hence subject to thermal embrittlement, concurrent exposure to high neutron fluence levels may result in a synergistic effect wherein the service-degraded fracture toughness is reduced from the levels predicted independently for either of the mechanisms. Therefore, components determined to be subject to thermal embrittlement require an additional consideration of the neutron fluence of the component to determine the full range of degradation mechanisms applicable for the component. The applicant will evaluate the degree of loss of fracture toughness associated with thermal embrittlement and embrittlement due to neutron radiation exposure, as appropriate. The results of this evaluation will directly effect the acceptable flaw size which may be left in-service when detected by the enhanced VT-1 examinations. The staff finds that the applicant’s approach is consistent with the staff’s Interim Staff Guidance, “Thermal Embrittlement of Cast Austenitic Stainless Steel Components,” dated May 2000. That is, enhanced VT-1 inspections, when coupled with acceptance criteria that account for all degradation mechanisms which may lead to loss of fracture toughness, are considered an acceptable supplemental examination as described in IWA-2210 of Section XI of the ASME Code. Therefore, the staff finds the applicant’s description of this attribute acceptable because it is in accordance with the Interim Staff Guidance.

Cracks of RV internals components fabricated from stainless steel and CASS will be evaluated for determination of the need and method of repair or replacement. The staff finds this approach acceptable because it is consistent with the acceptance criteria stated for Section XI.M16, “PWR Vessel Internals,” of the GALL Report.

Operating Experience: The VT-1, and in some cases, enhanced VT-1 examinations to be performed by this program are inspections with demonstrated capability and a proven industry record to detect potential cracking. Therefore, the staff finds that the applicant’s description of operating experience supports the attributes of the program described above.

Conclusion. The staff finds that this AMP will adequately manage cracking, loss of preload, dimensional changes, and reduction in fracture toughness of RV internals, such that the intended function(s) of the RV internals will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.0.7.3 FSAR Supplement

Sections 18.1.3 of Appendix A and Section 18.1.4 of Appendix A2 of the LRA provide the applicant’s FSAR supplement for the reactor vessel internals inspection program at St. Lucie Units 1 and 2, respectively. The program descriptions are consistent with the material contained in Section 3.1.4 of Appendix B and are, therefore, acceptable to the staff.

3.1.0.7.4 Conclusion

The staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA, as it relates to the applicant’s AMRs for the St. Lucie reactor vessel internals components. In addition, the staff reviewed the reactor vessel internals inspection program. In regards to this program, the applicant commits to submitting an integrated report for St. Lucie, Units 1 and 2, which will summarize the understanding of the aging effects applicable to the reactor vessel internals and will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie Units 1 and 2 inspection plans, including methods for detection and sizing of cracks and acceptance criteria. On the basis of the information in the application, the staff concludes that the applicant has demonstrated that the aging effects associated with the RV internals will be adequately managed so that there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation.

3.1.1 Reactor Coolant System Piping

3.1.1.1 Class 1 Reactor Coolant System Piping

The applicant described its AMR of the RCS Class 1 piping in LRA Section 3.1.1.1, “Class 1 Piping.” The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the Class 1 piping will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.1.1 Summary of Technical Information in the Application

In Section 3.1.1.1 and Table 3.1-1 of the LRA, the applicant stated that the Class 1 RCS piping components are fabricated from either carbon steel, carbon steel with stainless steel cladding, low-alloy steel, stainless steel (including CASS), Inconel Alloys (Alloys 600 or 690), or nickel-based alloy weld materials. In Table 3.1-1 of the LRA, the applicant stated that the Class 1 RCS piping components are exposed internally to the primary treated water environment and externally to either the containment atmosphere or postulated leaks of the primary treated water. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-2 of the LRA, respectively.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive Class 1 RCS piping components that are within the scope of license renewal—

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.1.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS piping and associated pressure boundary components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This also included the plant-specific operating experience at both subject plants.

Aging Management Programs. In Table 3.1-1 of the LRA, the applicant identified that the following aging management programs or activities will be used to manage the aging effects that are applicable to the Class 1 RCS piping components during the periods of extended operation—

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD ISI Program
- Boric Acid Wastage Surveillance Program
- Alloy 600 Inspection Program
- Thermal Aging Embrittlement of CASS Program
- Small Bore Class 1 Piping Inspection

3.1.1.1.2. Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RCS Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive Class 1 RCS piping components within the scope of license renewal—

- cracking in components that are fabricated from stainless steel, carbon steel with internal stainless steel clad surfaces, Alloy 600 or 690, or nickel-based alloy weld materials and are exposed internally to treated primary water environments

- cracking and reduction in fracture toughness in CASS components that are exposed internally to treated primary water environments

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of material in carbon steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a time-limited aging analysis for the components. The applicant's TLAA for the components is addressed in LRA Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components." The staff's evaluation of this TLAA is given in Section 4.3 of this SER.

Aging of Class 1 RCS Piping Components Exposed to Internal Environments. The Class 1 RCS Piping for St. Lucie does not include any carbon steel piping components whose carbon steel portions of the components are in direct internal contact with the treated (borated) primary coolant. All Class 1 RCS piping components that are fabricated from carbon steel are clad on their inside surfaces with austenitic stainless steel, and it is the austenitic stainless steel cladding that is in direct contact with the treated primary coolant. Loss of material and cracking are therefore not considered to be issues for the carbon steel portions of these components under internal liquid environments.

3.1 of the SRP-LR (NUREG-1800) does not identify that loss of material due to erosion or general corrosion is an issue for austenitic stainless steels (including CASS) or Inconel materials (e.g., nickel-based alloys such as Alloy 600 or Alloy 690 base metal materials or Alloy 82/182 or 52/152 filler metal materials) in the PWR environments because the materials are inherently resistant to general corrosion; however, loss of material may be an applicable effect for these components under wet conditions if the components have creviced areas that may be exposed to the fluids with high concentrations of halogens, sulfates, or oxygen. The applicant has not indicated in Chapter 3.1 of the application that the Class 1 piping components fabricated from austenitic stainless steel or Inconel materials are subject to vibrational levels that could subject the components to wear or have creviced regions that could subject the components to crevice or pitting corrosion. The applicant has therefore not identified loss of material as an applicable effect for the surfaces of components that are fabricated from stainless steel, carbon steel with stainless steel cladding, Alloy 600/690 or nickel-based alloy weld materials and that are exposed to treated primary water environments. The applicant's basis for concluding that loss of material by wear or by pitting/crevice corrosion is not an applicable effect for the austenitic stainless steel or Inconel Class 1 piping components is sufficiently summarized in Section 5.1 of the LRA. In this section, the applicant indicates that austenitic stainless steel (including CASS) and Inconel materials are not susceptible to general or pitting/crevice corrosion if the halogens, sulfates, and oxygen concentrations for the RCS are reduced below 150 ppb, 100 ppb, and 100 ppb, respectively. These concentrations are consistent with the recommended concentrations for the RCS coolant in the EPRI PWR Primary Water Chemistry Guidelines. The applicant uses the Chemistry Program-Water Chemistry Subprogram to reduce the halogen and oxygen concentrations in the RCS coolant below these levels. The staff evaluates this AMP in Section 3.0.5.6 of this SER.

Loss of material may also be an applicable effect in RCS components if the components are subject to wear. The austenitic stainless steel and Inconel materials in the RCS (including those in the Class 1 piping system) are also designed to be resistant to abrasive and erosive wear mechanisms. The staff therefore does not consider the austenitic stainless steel and Inconel Class 1 piping components to be susceptible to loss of material by wear.

Section 3.1 of the SRP-LR does not indicate that loss of material by general corrosion, pitting/crevice corrosion, or wear are applicable aging effects for Class 1 piping components fabricated from austenitic stainless steel or Inconel. The applicant's assessment of loss of material mechanisms for Class 1 piping components fabricated from austenitic stainless steels or Inconel is consistent with the staff's technical assessments discussed in the previous two paragraphs and with the staff's assessment in Section 3.1 of the SRP-LR, and therefore is acceptable to the staff.

According to Section 3.1 of the SRP-LR, RCS piping made from austenitic metals, including austenitic stainless steel, and Inconel alloys (including Alloy 600 and Alloy 690 base metals and nickel-based alloy weld metals) are known to be susceptible to stress corrosion cracking if the materials are exposed to the primary treated coolant (i.e., if the materials are known to be susceptible to primary water stress corrosion cracking or PWSCC) or if the internal surfaces of the pipe or component are in contact with oxygenated liquids or liquids with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. The applicant has identified in Table 3.1-1 of the application that cracking is an applicable effect for the surfaces of Class 1 stainless steel components, stainless steel cladding of clad carbon steel components, Alloy 600 and Alloy 690 base metal components, and nickel-based alloy welds that are exposed to treated primary water. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1) and is evaluated by the staff in Section 4.3.1 of this SER.

Irradiation embrittlement is not a concern for the RCS Class 1 piping and associated components because the expected neutron fluence is much less than the threshold level at which changes in properties of the material would occur. However, according to the staff's interim staff guidance (ISG) on cast austenitic stainless steel (CASS), CASS components may be susceptible to loss of fracture toughness as a result of thermal aging if certain metallurgical factors exist.[2] Thermal aging (thermal embrittlement) refers to the gradual and progressive changes in the microstructure and properties of a material due to extended exposure to elevated temperatures. The applicant has identified that reduction in fracture toughness is an additional aging effect for the Class 1 piping and valve components that are fabricated from CASS[3] and are exposed to the treated primary water. This assessment is consistent with the staff's corresponding assessment in Section 3.1 of the SRP-LR and is acceptable to the staff. The applicant proposed to use the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program to manage cracking and loss of fracture toughness in all Class 1 piping components fabricated from CASS materials.

The applicant also credited the Thermal Aging Embrittlement of CASS Program with managing loss of fracture toughness in the Class 1 piping, fitting, and safe-end components that are fabricated from CASS. In its review of the St. Lucie LRA, the staff determined that the applicant has adopted the guidelines in the staff's ISG (refer to footnote 1 below) on aging of Class 1 CASS components as the basis for determining whether the Thermal Aging Embrittlement of CASS Program needs to be credited as an additional program for managing this aging effect . These guidelines provide an acceptable basis for excluding the CASS Class 1 valve bodies from the scope of the Thermal Aging Embrittlement of CASS Program. The staff's evaluation of the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program is given in Section 3.0.5.3 of this SER. The staff's evaluation of the Thermal Aging Embrittlement of CASS Program is given in Section 3.1.0.2 of this SER. The applicant addresses the effect that reduction in fracture toughness will have on the leak-before-break analysis for the RCS main loop piping in Section 4.6.1 of the application. The staff evaluates this TLAA in Section 4.6.1 of this SER.

<u>Aging of Class 1 RCS Piping Components Exposed to External Environments</u>. The applicant has identified that loss of material due to boric acid-induced corrosion resulting from leakage of borated water onto the external surfaces of Class 1 RCS components made from carbon or low-alloy steel (including bolted connections, and integral attachments and supports) is a potential aging effect requiring aging management. This is consistent with the staff's corresponding assessment in Section 3.1 of the SRP-LR and is acceptable to the staff. The applicant's identification of aging effects for the low alloy steel bolting materials is discussed in more detail in the following paragraph.

The Class 1 RCS bolting is made out of low alloy steel (ferritic fasteners). These fasteners are stressed (pre-loaded) to ensure the integrity of the pressure boundary in Class 1 RCS bolted connections. The applicant has identified three potential mechanisms that can occur which may result in a loss of mechanical closure integrity for these materials: (1) stress relaxation, (2) aggressive chemical attack from leaks of borated primary coolant (treated primary water) and (3) stress corrosion cracking of high strength bolting materials. The first mechanism is a phenomenon in which the pre-loaded stress applied to the bolts for structural integrity loosens up over time. This phenomenon is known as stress relaxation. The second mechanism that

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1 Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,* Project No. 690, dated May 2000. The guidance in this document defines the metallurgical conditions and fabrication factors that can induce thermal aging in CASS materials.

2 The other aging effect is cracking, which was assessed by the staff in the previous paragraph.

can lead to a loss of mechanical closure integrity for the low alloy steel bolts is aggressive attack or corrosion as a result being exposed to potential leaks of the treated (borated) primary coolant. Industry experience and NRC generic communications have demonstrated that ferritic (carbon steel and low alloy steel) steel materials may be extremely susceptible to loss of material/aggressive corrosive attack when exposed to borated water. The bolts also may be susceptible to stress corrosion cracking, particularly if the yield strengths for the bolting materials are greater than 150 ksi. Therefore, the third mechanism that can lead to a loss of mechanical closure integrity for the low alloy steel bolts is stress corrosion cracking. Consistent with Section 3.1.1 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low alloy steel bolting materials also covers these three aging effects. These aging effects are consistent with the aging effects identified Section 3.1 of the SRP-LR for low alloy steel bolting materials and are therefore acceptable to the staff.

The applicant did not identify any aging effects as being applicable to RCS piping exposed to the containment air atmosphere. The applicant defines that containment air has a maximum temperature of 120°F and an average humidity of 73 percent. Carbon steel components that are exposed to moist (wet) air environments may be subject to general corrosion, pitting corrosion, crevice corrosion, or microbiologically influenced corrosion. Loss of material may be a concern for carbon steel components that are exposed to wetted air environments. During normal operations of the St. Lucie reactor units, the external surfaces of RCS piping components will be hotter than the ambient conditions within the containment. During periods of plant shutdowns, the humidity of the containment atmosphere is controlled by use of air conditioning units inside the containment structure.[4] Since precipitation will not occur under these operating conditions, the staff does not consider loss of material to be a concern for the surfaces of Class 1 carbon steel piping that are exposed to the containment air atmosphere at St. Lucie.

Aging Management Programs. The applicant indicated that the following existing and new programs will be used to manage the aging effects that are applicable to the Class 1 RCS piping components for the extended periods of operation at the St. Lucie reactor units—

- The Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in components that are fabricated from stainless steel (including cast austenitic stainless steel), carbon steel with internal stainless steel cladding, Inconel alloys (i.e., Alloy 600/690, or nickel-based alloy weld materials) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program to manage loss of mechanical closure integrity in low-alloy steel bolts that are exposed to containment air or could be exposed externally to leaks of the primary treated water (the applicant's combined use

4 In Table 3.0-2 of the St. Lucie application, the applicant provides the key parameters (temperature, relative humidity, etc.) for indoor and outdoor atmospheric environments at the plants. In footnote 2 of the table, the applicant clarifies that it uses the generic term "indoor air - not air conditioned" for external containment air or indoor air environments that create condensation or wetted conditions on the surfaces of the components.   The applicant's AMRs for the Class 1 piping does not indicate that any of the Class 1 piping components are exposed externally to "indoor air - not air conditioned" environments. Therefore, the staff do not consider loss of material due to general corrosion to be a concern for these components.

of the programs will account for loss of mechanical integrity that could be induced either by stress corrosion cracking, loss of material due to excessive chemical/corrosive attack, or loss of preload in the bolts)

- the Boric Acid Wastage Surveillance Program to manage loss of material in carbon steel piping, fittings, and nozzles that could be exposed externally to leaks of the primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in Class 1 Alloy 600/690 instrument nozzles, fittings, and thermowells and nickel-based alloy weld materials that are exposed internally to primary treated water

- the Thermal Aging Embrittlement of CASS Program to manage reduction in fracture toughness in Class 1 RCS components that are made from CASS and are exposed internally to primary treated water

- the Small Bore Class 1 Piping Inspection as an additional program to manage cracking in small bore (less than 4 inches in diameter) Class 1 piping, fittings, and safe-ends that are fabricated from stainless steel and are exposed internally to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the Class 1 piping and associated components and a mitigative means of minimizing cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff’s evaluation of this AMP is described in Section 3.0.5.6 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects that are applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive Class 1 RCS piping components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff’s evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, pumps, or valves and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed externally to leaks of the primary treated water. This program is consistent with the applicant’s surveillance program that is in effect in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluates this program in Section 3.0.5.4 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all Class 1 RCS components that are made from Alloy 600/690 base metals or nickel-based alloy weld metals and are susceptible to PWSCC. The staff’s evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Thermal Aging Embrittlement of CASS Program (Section 3.1.6 of Appendix B to the LRA) manages loss of fracture toughness in RCS piping, nozzle (including safe-ends), pump and valve components, and reactor vessel internal components fabricated from CASS. The staff's evaluation of this AMP is described in Section 3.1.0.2 of this SER.

The Small Bore Class 1 Piping Inspection (Section 3.1.5 of Appendix B to the LRA) manages age-related cracking in small bore Class 1 RCS piping less than 4 inches NPS. The staff's evaluation of this AMP is described Section 3.1.0.3 of this SER.

3.1.1.1.3 Conclusions

The staff has reviewed the information in Section 3.1.1.1 of the LRA, Table 3.1-1 of the LRA, and the applicant's response to RAI B.3.1.5, dated September 26, 2002, as the information relates to the applicant's AMRs for the St. Lucie Class 1 RCS piping components. On the basis of this review, with the exception of open items 3.0.2.2-1, 3.1.0.1-1, 3.1.0.1-2, and 3.1.0.3-1, the staff concludes that the applicant has demonstrated that aging effects associated with the Class 1 piping components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2 RCS Non-Class 1 Piping

The applicant describes its AMR of the RCS non-Class 1 piping in Section 3.1.1.2, "Non-Class 1 Piping," and Table 3.1-1 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the non-Class 1 piping will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2.1 Summary of Technical Information in the Application

In Section 3.1.1.2 and Table 3.1-1 of the LRA, the applicant identified that the non-Class 1 RCS piping components consist of valves, piping and fittings, thermowells, tubing and fittings, orifices, and bolting and that these components are fabricated from either carbon steel or stainless steel (including CASS) materials. In Table 3.1-1 of the LRA, the applicant identified that the non-Class 1 RCS piping components are exposed internally to the primary treated water environment and externally to either the containment atmosphere or postulated leaks of the primary treated water. The applicant defined these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA, respectively.

<u>Aging Effects</u>. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive Class 1 RCS piping components that are within the scope of license renewal—

- cracking
- reduction in fracture toughness
- loss of mechanical closure integrity

In accordance with Section 3.1.1.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS piping and associated pressure boundary components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for non-Class 1

RCS piping components at St. Lucie. This review also included the plant-specific operating experience at both subject plants.

Aging Management Programs. In Table 3.1-1 of the LRA, the applicant identified the following aging management programs or activities to be used to manage the aging effects that are applicable for the non-Class 1 RCS piping components during the periods of extended operation—

- ASME Section XI, Subsections IWB, IWC, and IWD ISI program
- boric acid wastage surveillance program
- chemistry control program

3.1.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the non-Class 1 RCS piping and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the non-Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

Aging Effects. In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive non-Class 1 RCS piping components within the scope of license renewal—

- cracking in components that are fabricated from stainless steel and are exposed internally to treated primary water environments

- cracking and reduction in fracture toughness in CASS components that are exposed internally to treated primary water environments

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant addresses thermal fatigue of non-Class 1 piping components in LRA Section 4.3.2, "ASME Boiler and Pressure Vessel Code, Section III, Class 2 and 3, and ANSI B31.1 Components." The staff's evaluation of the applicant's TLAA for non-Class 1 piping components is given in Section 4.3.2 of this SER.

Aging of non-Class 1 RCS Piping Components Exposed to Internal Environments. The applicant's identification of the aging effects applicable to the non-Class 1 RCS piping components that are exposed to the primary treated water environment is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same internal environment. This includes the applicant's identification of aging effects for non-Class 1 valves fabricated from CASS. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the non-Class 1 RCS piping components that are exposed to the primary treated water environment is consistent with the staff's corresponding analysis for these materials in the GALL Report, Section IV.C2, and is therefore acceptable to the staff.

Aging of Non-Class 1 RCS Piping Components Exposed to External Environments. The applicant's identification of the aging effects applicable to the non-Class 1 RCS piping components that are exposed to the containment air or postulated leaks of the primary treated water is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same external environment. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. The applicant did not indicate in Chapter 3.1.1.2 of the LRA that the non-Class 1 piping components fabricated from austenitic stainless steel are subject to abrasive or erosive mechanisms that could subject the components to wear or have creviced regions that could subject the components to crevice or pitting corrosion. The applicant therefore did not identify loss of material as an applicable effect for the surfaces of non-Class 1 piping and valve components that are fabricated from stainless steel (including CASS). The applicant's basis for concluding that loss of material by wear or by pitting/crevice corrosion is not an applicable effect for the austenitic stainless steel or Inconel Class 1 piping components is sufficiently summarized in Section 5.1 of the LRA. The staff's evaluation of the topic of loss of material in the non-Class 1 piping components is identical to the staff's assessment regarding the applicability of loss of material mechanisms to Class 1 austenitic stainless steel piping components, which is given in Section 3.1.0.2 of this SER.

Section 3.1 of the SRP-LR does not indicate that loss of material by general corrosion, pitting/crevice corrosion, or wear is an applicable aging effect for RCS piping components fabricated from austenitic stainless steels. The applicant's assessment of loss of material mechanisms for Class 1 piping components fabricated from austenitic stainless steels is consistent with the staff's technical assessment discussed in Section 3.1.1.1.2 of this SER and with the staff's assessment in Section 3.1 of the SRP-LR and therefore is acceptable to the staff.

For bolting materials, loss of mechanical closure integrity covers loss of closure integrity due to stress relaxation, due to wear, and for carbon steel bolts and low alloy steel bolts due to aggressive corrosive attack if the bolts are exposed to primary coolant leaks. Industry experience has demonstrated that stainless steel bolting is not susceptible to aggressive corrosive attack in the manner that this carbon steel or low alloy steel bolting is. It should be noted that the non-Class 1 RCS bolting is made of either stainless steel or carbon steel (ferritic fasteners). The applicant has appropriately identified that loss of mechanical closure integrity due to aggressive attack as an applicable effect for the carbon steel non-Class 1 bolting in the same manner it identified the RCS Class 1 bolting fabricated from low-alloy steel. However, the applicant did not identify the loss of mechanical closure integrity as an applicable effect for the stainless steel or carbon steel non-Class 1 bolting materials as a result of stress relaxation.

The applicant needs to justify why it does not consider loss of mechanical closure integrity due to stress relaxation is an applicable effect for the stainless steel and carbon steel non-Class 1 bolting materials. If loss of mechanical closure integrity due to stress relaxation to be an applicable effect for the stainless steel and carbon steel non-Class 1 bolting materials, the AMRs for these bolting materials need to be amended to reflect loss of mechanical closure integrity as an applicable effects. An applicable inspection-based AMP must be proposed to manage loosening of the bolts during the extended periods of operation for the St. Lucie units. This is open item 3.1.1.2-1.

Based on the staff's evaluation of these materials given in Section 3.1.1.1 of the SER, with the exception of the applicant's proposed management of stress relaxation in the non-Class 1 bolting components (refer to Open Item 3.1.1.2-1), the staff concludes that the applicant's identification of aging effects for the non-Class 1 RCS piping components that are exposed to the containment air or postulated leaks of the primary treated water is consistent with the staff's corresponding analysis for these materials in the Section 3.1 of the SRP-LR and is therefore acceptable to the staff.

3.1.1.2.3 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects that are applicable to the non-Class 1 RCS piping components within the extended periods of operation for the St. Lucie reactor units—

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in non-Class 1 RCS piping components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage reduction in fracture toughness in non-Class 1 RCS components that are made from CASS and are exposed to primary treated water

- the Boric Acid Wastage Surveillance Program to material in carbon steel bolting that could be exposed to postulated leaks of the primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the non-Class 1 piping components and a mitigative means of minimizing cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.6 of this SER.

The applicant has proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) to manage reduction in fracture toughness in non-Class 1 RCS valves fabricated from CASS.[5] The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects that are applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive non-Class 1 (Class 2 or 3) RCS piping components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, pumps or valves, and loss of mechanical integrity in low-alloy steel/carbon steel bolting due to corrosion caused by exposure to primary treated water from the RCS. This program is consistent with the applicant's surveillance program that is in effect in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluates this program in Section 3.0.5.4 of this SER.

3.1.1.2.4 Conclusion

The staff has reviewed the information in Section 3.1.1.2 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the St. Lucie non-Class 1 RCS piping components. On the basis of this review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the non-Class 1 piping components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Pressurizer

The applicant describes its AMR of the RCS pressurizer in Section 3.1.2, "Pressurizer," and Table 3.1-1 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the pressurizer and its components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1 Summary of Technical Information in the Application

In Section 3.1.2 and Table 3.1-1 of the LRA, the applicant states that the St. Lucie pressurizer components consist of shells; upper heads; lower heads; spray, surge, relief valve, and safety valve nozzles and their associated safe-ends; instrumentation nozzles; heater sleeves manway covers; heater sheaths; and thermowells. These components are fabricated from either carbon steel with stainless steel inserts, stainless steel (including CASS), Inconel alloys (i.e., Alloy 600, Alloy 690, or nickel-plated Alloy 600), or low-alloy steel with either stainless steel or Alloy 82/182 cladding. In Table 3.1-1 of the LRA, the applicant states that the pressurizer components are exposed internally to the primary treated water environment and externally to

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5 The staff's basis for concluding that the Thermal Aging of CASS Program does not need to be credited as an additional AMP for managing loss of fracture toughness in RCS valves fabricated from CASS is given in Section 3.1.1.1.2 of this SER under the heading "Aging of Class 1 RCS Piping Components Exposed to External Environments."

either the containment atmosphere or concentrated boric acid resulting from leaks of the primary treated water. The applicant defines these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA, respectively.

3.1.2.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive pressurizer components which are within the scope of license renewal—

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.2 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the pressurizer components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.2.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following aging management programs or activities to be used to manage the aging effects that are applicable to the pressurizer components during the periods of extended operation—

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD ISI Program
- Boric Acid Wastage Surveillance Program
- Alloy 600 Inspection Program
- Thermal Aging Embrittlement of CASS Program

3.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1.1 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the pressurizer and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the pressurizer and associated components that are within the scope of the license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

3.1.2.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified the following aging effects as applicable to the passive pressurizer components within the scope of license renewal—

- cracking in components that are exposed internally to treated primary water environments and are fabricated from stainless steel, carbon steel with stainless steel inserts, Inconel alloys (i.e., Alloy 600/690, nickel-plated Alloy 600, or nickel-based weld materials), or low-alloy steel with stainless steel or Alloy 82/182 cladding

- cracking and reduction in fracture toughness in cast austenitic stainless steel components that are exposed internally to treated primary water environments

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of material in carbon steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The pressurizer components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant's TLAA for the components is addressed in LRA Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class 1 Components." The staff's evaluation of this TLAA is given in Section 4.3 of this SER.

Aging of Pressurizer Components Exposed to Internal Environments. With the exception of the applicant's AMR for the pressurizer surge and spray nozzle thermal sleeves, the applicant's identification of the aging effects applicable to the pressurizer components that are exposed to the primary treated water environment is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same internal environment. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the pressurizer components that are exposed to the primary treated water environment is consistent with the staff's corresponding analysis for these materials in the GALL Report, Section IV.C2, and is therefore acceptable to the staff.

By letter dated October 3, 2002, in response to RAI 2.3.1-2, the applicant included the pressurizer surge and spray nozzle thermal sleeves within the scope of license renewal and provided the following AMR for these components—

Component Commodity Group	Intended Function	Material	Environment	Aging Effects Requiring Management	Aging Management Programs

Pressurizer Surge Nozzle Thermal Sleeves (IV.C2.5.5) Pressurizer Spray Nozzle Thermal Sleeves (IV.C2.5.5)	Pressure Boundary[a]	Alloy 600	Treated Water - Primary	None	None Required

a. The pressurizer surge and spray nozzle thermal sleeves are not part of the pressure boundary.

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 materials and are welded to the low-alloy steel pressurizer surge and spray nozzles using Alloy 182/82 weld metals. Industry experience has demonstrated that these weld materials are susceptible to PWSCC. In its AMR provided October 3, 2002, the applicant concluded that there are no applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves because the applied loads on the thermal sleeves are low. In Section 5.1 of the application, the applicant has provided an acceptable basis for concluding the loss of material due to wear and/or crevice corrosion is not an applicable effect for Alloy 600 components in the St. Lucie RCS. However, the attachment welds for the pressurizer surge and spray nozzle thermal sleeves may contain high residual stresses that result from solidification of the weld metal from the molten state. Therefore, contrary to the applicant's assessment, the staff concludes that the attachment welds for the pressurizer surge and spray nozzle thermal sleeves may be susceptible to cracking as a result of PWSCC and that the applicant's supplemental AMR for the pressurizer thermal sleeves needs to be revised to include cracking as an applicable effect for the components, and that appropriate aging management programs be proposed to manage cracking in these components. This is characterized as open item 3.1.2.2-1.

<u>Aging of Pressurizer Components Exposed to External Environments</u>. The applicant's identification of the aging effects that are applicable to the pressurizer components that are exposed to the containment air or postulated leaks of the primary treated water (i.e., postulated borated water leakage) is equivalent to the applicant's analysis and identification of aging effects for corresponding Class 1 RCS piping materials exposed to the same external environment. The staff has evaluated these materials in Section 3.1.1.1.2 of this SER. Based on this evaluation, the staff concludes that the applicant's identification of aging effects for the pressurizer components that are exposed to the containment air or postulated leaks of the primary treated water is consistent with staff's corresponding analysis for these materials in the GALL Report, Section IV.C2, and is therefore acceptable to the staff.

3.1.2.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the pressurizer components within the extended periods of operation for the St. Lucie reactor units:

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in components that are exposed internally to primary treated water and are fabricated from stainless steel (including CASS), carbon steel with stainless steel inserts, Inconel alloys (i.e., Alloy 600/690 or nickel-plated Alloy 600) or low-alloy steel with Alloy 82/182 or stainless steel cladding

- the Chemistry Control Program to manage cracking in the carbon steel manway covers that are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program to manage loss of mechanical integrity in low-alloy steel bolts that are exposed to containment air or could be exposed to postulated leaks of the primary treated water (the applicant’s combined use of the programs will account for loss of mechanical integrity that could be induced by either stress corrosion cracking, loss of material due to excessive chemical/corrosive attack, or loss of preload in the bolts)

- the Boric Acid Wastage Surveillance Program to manage loss of material in carbon steel manway covers that could be exposed to postulated leaks of the primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in pressurizer components that are made from Inconel materials (i.e., Alloy 600/690 or nickel-plated Alloy 600) and are exposed to primary treated water.

- the Thermal Aging Embrittlement of CASS Program to manage reduction in fracture toughness in Class 1 RCS components that are made from CASS and are exposed to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the pressurizer components and a mitigative means of minimizing loss of material and cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff’s evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive pressurizer components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff’s evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, piping, pumps or valves, and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed to postulated leakage of the primary treated water from RCS. This program is consistent with the applicant’s surveillance program that is in effect in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluates this program in Section 3.0.5.4 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all pressurizer components that are made from Alloy 600/690 base metals or nickel-based weld metals and are susceptible to PWSCC. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Thermal Aging Embrittlement of CASS Program (Section 3.1.6 of Appendix B to the LRA) manages loss of fracture in RCS piping, nozzle (including safe-ends), pump and valve components, and reactor vessel internal components fabricated from CASS. The staff's evaluation of this AMP is described in Section 3.1.0.2 of this SER.

3.1.2.3 Conclusion

The staff has reviewed the information in Section 3.1.2 and Table 3.1-1 of the LRA as it relates to the applicant's AMRs for the pressurizer components, as amended by the information provided in the applicant's response to RAI 2.3.1-2, dated October 3, 2002. On the basis of this review, with the exception of open items 3.0.2.2-1, 3.1.0.1-1, and 3.1.0.1-2 and confirmatory items 3.0.2.2-1and 3.0.5.4-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the pressurizer will be adequately manged so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Reactor Vessels

In Section 3.1.3, "Reactor Vessels," of the LRA, the applicant describes its AMR of the RVs. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the RV components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.1 Summary of Technical Information in the Application

In Section 3.1.3 and Table 3.1-1 of the LRA, the applicant identifies that the RV components are fabricated from stainless steel, Alloy 600, low-alloy steel, low-alloy steel with stainless steel cladding, carbon steel, and carbon steel with stainless steel cladding. In Table 3.1-1 of the LRA, the applicant identified that the RV components are exposed internally to primary treated water and externally to containment air and borated water leaks. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-2 of the LRA, respectively.

3.1.3.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable for the passive RV components that are within the scope of license renewal:

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity

In accordance with Section 3.1.3 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This also included the plant-specific operating experience at both subject plants.

3.1.3.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified that the following AMPs or activities will be used to manage the aging effects applicable for the RV components during the periods of extended operation:

- Chemistry Control Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- Alloy 600 Inspection Program
- Reactor Vessel Integrity Program
- Boric Acid Wastage Surveillance Program

3.1.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.3, and Table 3.1-1, and pertinent sections of Appendices A and B of the LRA, regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RV and associated components will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the RV components that are within the scope of license renewal and require AMRs, identified the aging effects that require management for these components, and identified the AMPs that will be used to manage these effects.

3.1.3.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive RV components within the scope of license renewal:

- cracking in components that are fabricated from stainless steel, carbon steel, low-alloy steel with internal stainless steel clad surfaces, and Alloy 600, and are exposed internally to treated primary water environments

- reduction in fracture toughness in low-alloy steel with stainless steel cladding that is exposed internally to treated primary water environments

- loss of material in Alloy 600 components (core stabilizing lugs) that are exposed internally to primary treated water environments

- loss of material in carbon steel and low-alloy steel components that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of mechanical closure integrity in low-alloy steel components (closure studs, nuts, and washers) that are exposed externally to postulated leakage from the primary treated water environment (i.e., borated water leaks)

- loss of material in low-alloy steel components that are exposed externally to containment air

Fatigue. The potential for cracking to occur in carbon or low-alloy steel RV materials is predominantly a phenomenon of thermal fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Section 4.3.1 of the LRA. The staff's evaluation of this TLAA is given in Section 4.3 of this SER.

Aging of Reactor Vessel Components Exposed to Internal Environments. The RV components for St. Lucie do not include any carbon steel components in direct internal contact with the treated (borated) primary coolant. All RV components that are fabricated from carbon steel are clad on their inside surfaces with austenitic stainless steel, and it is the austenitic stainless steel cladding that is in direct contact with the treated primary coolant. Loss of material and cracking are therefore not considered to be issues for the carbon steel portions of these components under internal liquid environments.

According to Section 3.1 of the SRP-LR, loss of material due to erosion or general corrosion is not normally an issue for austenitic stainless steel or Inconel materials (e.g., Alloy 600 base metal materials) in the PWR environments because the materials are inherently resistant to erosion and general corrosion. The staff compared the applicant's AMRs for Inconel and austenitic stainless steel RV components to corresponding AMRs in Section 3.1 of the SRP-LR. These AMRs were found to be consistent with Section 3.1 of the SRP-LR, and therefore acceptable to the staff.

The applicant indicated in Section 3.1 of the application that the core support lugs fabricated from Inconel material are subject to vibrational levels that could subject the components to wear. The applicant has therefore identified loss of material as an applicable effect for the core support lugs fabricated from Alloy 600. Loss of material of the core support lugs is an aging effect that is consistent with the staff's position on previous license renewal applications (Turkey Point) and therefore acceptable to the staff.

Austenitic stainless steel and Inconel alloys are susceptible to stress corrosion cracking under certain conditions in the PWR water environment. The applicant has identified in Table 3.1-1 of the application that cracking is an applicable effect for the surfaces of RV stainless steel components, stainless steel cladding of clad carbon steel components, and Alloy 600 base metal components that are exposed to treated primary water. These components include the control element drive mechanisms and the in-core instrumentation nozzle tube and the core stabilizing and stop lugs. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1), and is evaluated by the staff in Section 4.3.1 of this SER.

Reduction in fracture toughness is also of concern during the period of extended operation for the RV intermediate and lower shells. The alloy steel weld and base metals in the RV beltline are subject to reduction in fracture toughness as a result of neutron embrittlement. The applicant has identified reduction in fracture toughness as an applicable effect for the RV beltline base metal and weld materials. The applicant addresses reduction of fracture toughness of the RV beltline materials in the TLAA for the RV materials, as given in Section 4.3 of the application. The staff' evaluation of the TLAA for the RV beltline materials is given in Section 4.3 of this SER.

Reduction in fracture toughness may also occur in certain types of CASS components as a result of prolonged exposure to service temperatures above 250 ^{o}C (482 ^{o}F) (i.e., as a result of thermal aging). The applicant, however, did not identify any RV components that are fabricated from CASS.

<u>Aging of Reactor Vessel Components Exposed to External Environments</u>. Loss of material may occur in the RV components under certain conditions. Carbon steel and low-alloy steel components may be susceptible to general-corrosion-induced loss of material under wet or damp conditions. Industry experience also demonstrates that borated water leakage from the RCS may corrode carbon or low-alloy steel RCS pressure boundary components. NUREG/CR-5576 provides a summary of boric acid wastage events that had occurred in primary alloy or carbon steel pressure boundary components of domestic PWRs through 1990. The applicant has identified that loss of material is an applicable effect for the exterior surfaces of carbon or low-alloy steel RV components that could be subjected to potential borated water leakage from the pressurizer. Therefore, the following carbon or low-alloy steel RV components may be susceptible to loss of material (1) RV steel shells, flanges, rings, bottom heads, closure head domes, and primary inlet/outlet nozzles, (2) high strength alloy steel bolting materials, and (3) alloy steel integral attachments (nozzle supports and safe-ends). This is consistent with the staff's assessment in Section 3.1 of the SRP-LR and is acceptable to the staff.

The RV bolting is made out of low-alloy steel (ferritic fasteners). These fasteners are stressed (preloaded) to ensure the integrity of the pressure boundary in RV bolted connections. The applicant has identified three potential mechanisms that can occur which may result in a loss of mechanical closure integrity for these materials (1) stress relaxation, (2) aggressive chemical attack from leaks of borated primary coolant, and (3) stress corrosion cracking of high strength bolting materials. The first mechanism is a phenomenon in which the preloaded stress applied to the bolts for structural integrity loosens up over time. This phenomenon is known as stress relaxation. The second mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is corrosion as a result of being exposed to potential leaks of the treated (borated) primary coolant, as discussed in the preceding paragraph. Industry experience and NRC generic communications have demonstrated that ferritic (carbon steel and low-alloy steel) steel materials may be susceptible to aggressive corrosive attack when exposed to borated water. The third mechanism that can lead to loss of mechanical closure integrity is stress corrosion cracking (SCC), particularly if the yield strengths for the bolting materials are greater than 150 ksi. Consistent with Section 3.1.1 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low-alloy steel bolting materials also covers these three aging effects. These aging effects are consistent with the aging effects identified in Section 3.1 of the SRP-LR for low-alloy steel bolting materials and are therefore acceptable to the staff.

The applicant identified loss of material as being an applicable aging effect for the RV closure studs, nuts, washers, and vessel flanges exposed to containment air atmosphere. The applicant defines that containment air has a maximum temperature of 120 °F and an average humidity of 73 percent. Low-alloy steel components that are exposed to moist (wet) air environments may be subject to general corrosion. Loss of material, therefore, is considered by the staff to be a concern for the external surfaces of the subject RV components in containment air atmospheres for St. Lucie. This is consistent with the aging effects identified in Section 3.1 of the SRP-LR for the RV bolting and vessel flanges exposed to containment air and is therefore acceptable to the staff.

3.1.3.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the RV components for the extended periods of operation for the St. Lucie reactor units:

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in components that are fabricated from stainless steel, low-alloy steel with stainless steel cladding, Alloy 600 (core stabilizing lugs and stop lugs), and carbon steel that are exposed internally to primary treated water

- the Alloy 600 Inspection Program as an additional program to manage cracking in control element drive mechanism nozzle tubes and motor housing lower end fittings, vent pipes, and incore instrumentation nozzle flange adaptors/upper flanges that are fabricated from Alloy 600 and exposed internally to primary treated water

- the Reactor Vessel Integrity Program to manage reduction in fracture toughness of RV beltline materials

- the Boric Acid Wastage Surveillance Program to manage loss of material in low-alloy steel closure head domes and flanges, primary inlet nozzles, shells, bottom heads, and carbon steel safe-ends that could be exposed to postulated leaks of the primary treated water

- the Boric Acid Wastage Surveillance Program to manage loss of mechanical integrity of closure studs, nuts, and washers that could be exposed externally to postulated leaks of the primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material of Alloy 600 core stabilizing lugs that are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material of low-alloy steel vessel flanges and RV studs, nuts, and washers that are exposed externally to containment air

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RV components, and a mitigative means of minimizing cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive RV components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The applicant credits the Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA) for managing cracking in all RV components that are made from Alloy 600 base metals that are susceptible to PWSCC. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of material in carbon and low-alloy steel vessels, closure head domes and flanges, inlet and outlet nozzles and safe-ends, and loss of mechanical integrity in low-alloy steel/carbon steel bolting that could be exposed to postulated leakage of the primary treated water from the RCS. This program is consistent with the applicant's surveillance program that is in effect in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluates this program in Section 3.0.5.4 of this SER.

The applicant credits the Reactor Vessel Integrity Program (Section 3.2.12 of Appendix B to the LRA) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. The staff's review of this AMP is provided in Section 3.1.0.5 of this SER.

3.1.3.3 Conclusion

With the exception of open items 3.0.2.2-1, 3.1.0.1-1, 3.1.0.1-2, and 3.1.0.5-1, the staff concludes that the applicant has demonstrated that the aging effects associated with RVs will be adequately managed so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.4-1, The staff also concludes that the FSAR supplement contains an appropriate summary description of the program activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.1.4 Reactor Vessel Internals

The applicant describes its AMR of the reactor vessel internals (RVI) in LRA Section 3.1.4, "Reactor Vessel Internals." The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the RVI components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4.1 Summary of Technical Information in the Application

In Section 3.1.4 and Table 3.1-1 of the LRA, the applicant identified that the RV internals components are fabricated from stainless steel and CASS. In Table 3.1-1 of the LRA, the applicant identified that the RV internals components are exposed internally to primary treated water. The applicant defined this internal environment in Table 3.0-1 of the LRA.

3.1.4.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable for the passive RV internals components that are within the scope of license renewal:

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity
- loss of preload
- dimensional change

In accordance with Section 3.1.3 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV internals components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.4.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified that the following AMPs or activities will be used to manage the aging effects applicable for the RV internals components during the period of extended operation:

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

3.1.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA, as well as pertinent sections of Appendices A and B to the LRA, regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RV internals, and associated components, will be maintained consistent with the CLB throughout the period of extended operation.

Table 3.1-1 of the LRA lists the RV internals components that are within the scope of license renewal and require an AMR, identifies the aging effects that require management for these components, and identifies the AMPs that will be used to manage these effects.

3.1.4.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified that the following aging effects are applicable to the passive RV internals components within the scope of license renewal:

- cracking in components that are fabricated from stainless steel or CASS and are exposed to primary treated water environments

- reduction of fracture toughness in components that are fabricated from stainless steel or CASS and are exposed to primary treated water environments

- loss of material due to wear in components that are fabricated from stainless steel that are exposed to primary treated water environments

- loss of preload of the hold down ring that is fabricated from stainless steel and is exposed to primary treated water environments

- loss of mechanical closure integrity of bolts, core support lug bolts, and tie rods that are fabricated from stainless steel and are exposed to primary treated water environments

- dimensional changes of components that are fabricated from stainless steel and are exposed to primary treated water environments (due to void swelling)

<u>Fatigue</u>. The potential for cracking to occur in stainless steel and CASS RV internals materials is predominantly a phenomenon of thermal fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. At St. Lucie, cracking due to fatigue is identified as a TLAA and is addressed in Section 4.3.1 of the LRA. The staff's evaluation of the TLAA is given in Section 4.3 of this SER.

<u>Aging of Reactor Vessel Internals Components Exposed to the Primary Treated Water Environment.</u> Cracking of the RV internals due to either SCC or irradiation-assisted stress corrosion cracking (IASCC) is an applicable aging effect for RV internals. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for bolting, given the potential for occluded environmental conditions in crevice areas. IASCC is SCC that is enhanced by exposure of the materials to ionizing radiation. Cracking of the RV internals may also occur due to thermal fatigue, as discussed in the preceding paragraph. In LRA Table 3.1-1, the applicant has identified cracking as an applicable aging effect for RV internals. This is acceptable to the staff because it accounts for the aging effects of cracking due to SCC or IASCC, and because it is in accordance with Section Section 3.1 of the SRP-LR, which states that cracking is an applicable aging effect for all PWR RV internals.

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 RV internals components fabricated from CASS are potentially subject to reduction in fracture toughness due to thermal embrittlement, as addressed in the ISG, License Renewal Issue No. 98-0030, "Thermal Embrittlement of Cast Austenitic Stainless Steel Components," dated May 19, 2000. The applicant identified that the CASS components in the RV internals for St. Lucie Units 1 and 2 include flow bypass inserts (Unit 2 only), single tube control element assembly (CEA) shrouds, and core support columns (Unit 1 only). The applicant identified that reduction of fracture toughness is an applicable aging effect for all RV internals made out of CASS. This is acceptable to the staff because it accounts for the aging effects of thermal embrittlement of the fracture toughness properties of CASS RV internals, and because it is in accordance with Section 3.1 of the SRP-LR, which states that reduction of fracture toughness is an applicable aging effect for all PWR RV internals fabricated from CASS.

Reduction in fracture toughness may also occur due to irradiation embrittlement. Exposure to high energy neutrons can cause changes in the properties of stainless steel used in RV internals. Neutron irradiation can produce changes in mechanical properties by increasing yield and ultimate strength, and decreasing ductility and fracture toughness of RV internals component materials. In Section 3.1.4.2.2 of the LRA, the applicant listed several RV internals components (which include the core support barrels, core support barrel upper flanges, alignment keys, core shroud assemblies, core support plates, etc.) that are located in the active fuel region and are exposed to high fluence, thus causing the components to be potentially susceptible to irradiation embrittlement. This is acceptable to the staff because it accounts for the aging effects of irradiation embrittlement on the fracture toughness properties of stainless steel RV internals, and because it is in accordance with Section 3.1 of the SRP-LR, which states that reduction of fracture toughness is an applicable aging effect for RV internals fabricated from stainless steel that are exposed to fluences greater than 1×10^{21} n/cm^2.

According to Section 3.1 of the SRP-LR, loss of material due to erosion or general corrosion is not normally an issue for austenitic stainless steel materials in the PWR environments because the materials are inherently resistant to erosion and general corrosion. The staff compared the applicant's AMRs for austenitic stainless steel RV internals components to corresponding AMRs in Section 3.1 of the SRP-LR. These AMRs were found to be consistent with Section 3.1 of the SRP-LR, and therefore are acceptable to the staff.

Loss of material from wear of RV internals occurs due to relative motion between the interfaces and mating surfaces of components caused by flow-induced vibration during plant operation, differential thermal expansion and contraction movements during plant heatup and cooldown, and changes in power operating cycles. The severity of the wear depends on the frequency of motion, duration, and component loadings. The applicant identified loss of material due to mechanical wear for several RV internals components, including fuel alignment plates (Unit 2 only), fuel alignment plate guide lugs (Unit 1 only), fuel alignment plate guide lug inserts, hold down rings, CEA extension shaft guides, core support barrel upper flanges, core support barrel alignment keys, fuel alignment pins, and snubber spacer blocks. This is acceptable to the staff because (1) it is consistent with Section IV.B3 of the GALL Report, Volume 2, which states that loss of material is an applicable aging effect for these RV internals components of PWRs, and (2) specifically accounts for loss of material that could be induced by wear.

Stress relaxation may be defined as the unloading of preloaded components under conditions of long-term exposure of RV internals materials to high constant strain, elevated temperature, and/or neutron irradiation. Loss of preload due to stress relaxation is an applicable aging effect for those RV internals with substantial preload. A loss of preload in these components could result in higher cyclic and transient loads and a loss of function. The combination of bolt stress relaxation, changes in transient and high cycle vibration of the RV internals, and the effects of increased RV internals fatigue susceptibility may be significant for the license renewal period. The applicant identified the hold down rings as the RV internals components that are susceptible to loss of preload due to stress relaxation. This is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR, which states that loss of preload is an applicable aging effect for the RV internals hold down rings.

Loss of mechanical closure integrity of fuel alignment plate guide lug bolts (Unit 1 only), fuel alignment plate guide lug insert bolts, and CEA shroud bolts can occur due to cracking and stress relaxation. Loss of mechanical closure integrity associated with the core shroud tie rods (Unit 1 only) and snubber bolts (Unit 1 only) can occur due to cracking, reduction in fracture toughness (irradiation embrittlement), and stress relaxation. The identification of loss of mechanical closure integrity due to cracking and stress relaxation for these RV internals components is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR.

Void swelling is defined as a gradual increase in dimensions of the RV internals. Under reactor internals irradiation conditions, helium is generated as a nuclear transmutation reaction product. At sufficiently high temperatures, helium bubbles expand to a critical diameter and coalesce (unite) into larger bubbles. These bubbles create void areas (gaps) in the materials and may result in the swelling of the material. Swelling changes the dimensions of the material and may affect the ability of the particular RV internal component to perform its intended functions. Although void swelling has not been observed to date, the staff is concerned that void swelling may become significant during the period of extended operation. Until the industry has developed sufficient data to demonstrate that void swelling is not a significant aging mechanism, the staff believes that void swelling should be considered significant, and applicants for license renewal should describe their AMP to address void swelling. In LRA Table 3.1-1, the applicant has identified change in dimension as an applicable aging effect for some of the RV internals. The identification of dimensional changes due to void swelling for these RV internals components is acceptable to the staff because it is consistent with Section 3.1 of the SRP-LR.

Uncertainty currently exists relative to the prediction of void swelling in PWR conditions. This uncertainty is based on the fact that existing swelling data have been obtained from materials that were not irradiated in a PWR environment. Void swelling is a complex function of neutron flux, neutron fluence, operating temperature, operating stress, material composition, and the material fabrication process. However, the key environmental factors influencing void swelling are cumulative radiation dose and temperature.

Presently, data are not available to ascertain a specific threshold for the onset of void swelling in solution annealed Type 304 stainless steel in a PWR environment. However, the onset of void swelling in solution annealed and 10, 20, and 30 percent cold-worked Type 304 stainless steel exposed to a breeder reactor environment is available, and is estimated to start at fluence levels of approximately 4 to 8 x 10^{22} n/cm^2 (E > 1 MeV) at a temperature of 440 ^{o}C (824 ^{o}F) (*Effects of Radiation on Materials*, ASTM STP 725, "Comparison of High-Fluence Swelling Behavior of Austenitic Stainless Steels", P. 484). PWRs operate at approximately 315 ^{o}C (599 ^{o}F), well below 440 ^{o}C (824 ^{o}F). FPL indicated that its Reactor Vessel Internals Inspection

Program includes an evaluation of dimensional changes due to void swelling. The applicant further stated that if the dimensional changes due to void swelling are determined to be significant, program inspections would be performed.

The applicant is currently participating in industry programs which are addressing the significance of void swelling. These programs are addressing both the physical phenomenon of void swelling, as well as the safety significance. The Reactor Vessel Internals Inspection Program (Section 3.1.4 of Appendix B to the LRA) addresses the applicant's actions with respect to identification and inspection of RV internals components susceptible to void swelling, including participation in the industry's program to address this issue. The staff's evaluation of this AMP is documented in Section 3.1.4.2.2 of this SER.

3.1.4.2.2 Aging Management Programs

The applicant indicated that the following programs will be used to manage the aging effects applicable to the RV internals components for the extended period of operation for the St. Lucie reactor units:

- the Chemistry Control Program; ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program; and the Reactor Vessel Internals Inspection Program to manage cracking in RV internals components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Reactor Vessel Internals Inspection Program to manage reduction in fracture toughness of RV internals components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of material and loss of preload in RV internals components that are fabricated from stainless steel and are exposed internally to primary treated water

- the Chemistry Control Program; ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program; and the Reactor Vessel Internals Inspection Program to manage loss of mechanical closure integrity of RV internals components that are fabricated from stainless steel and are exposed internally to primary treated water

- the Reactor Vessel Internals Inspection Program to manage dimensional changes due to void swelling of RV internals components that are fabricated from stainless steel and are exposed internally to primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RV internals components, as well as a mitigative means of minimizing loss of material and cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is documented in Section 3.0.4.5 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section B.3.2.2.1 of Appendix B to the LRA) manages the aging effects of loss of material, cracking, loss of preload, and reduction in fracture toughness. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsection IWB. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The staff's evaluation of this AMP is documented in Section 3.0.4.3 of this SER.

The Reactor Vessel Internals Inspection Program (Section 3.1.4 of Appendix B to the LRA) manages aging effects of cracking due to IASCC and SCC, reduction in fracture toughness due to irradiation and thermal embrittlement, loss of mechanical closure integrity of bolted joints on accessible parts of the St. Lucie Units 1 and 2 RV internals components, and dimensional changes due to void swelling. This program consists of a surface examination (VT-1 or enhanced VT-1) that typically includes remote visual inspections. This program also provides screening criteria to determine the susceptibility of CASS parts to thermal embrittlement based on the casting method, molybdenum content, and percent ferrite. The staff's evaluation of this program is in Section 3.1.0.7 of this SER.

3.1.4.3 Conclusion

The staff reviewed the information included in Section 3.1.4 and Table 3.1-1 of the LRA as it relates to the applicant's AMRs for the St. Lucie RV internals components. In addition, the staff reviewed the Reactor Vessel Internals Inspection Program. With the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the RV internals will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5 Reactor Coolant Pumps

In Section 3.1.4, "Reactor Coolant Pumps," of the LRA, the applicant describes its AMR of the reactor coolant pumps. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the reactor coolant pumps (RCPs) will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5.1 Summary of Technical Information in the Application

In Section 3.1.5 and Table 3.1-1 of the LRA, the applicant identifies the RCP components that require an aging management review. These components consist of casings, covers, lower seal heat exchanger tubes, and bolting. In addition, the applicant states that these components are fabricated from either stainless steel, cast stainless steel, or low-alloy steel. In Table 3.1-1 of the LRA, the applicant states that the RCP components are exposed internally to primary treated water and other treated water environments and externally to either the containment atmosphere or postulated leaks of the primary treated water (i.e., borated water leakage environments). The applicant defines these internal and external environments in Tables 3.0.1 and 3.0.2 of the LRA.

3.1.5.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects applicable to the passive RCP components, which are within the scope of license renewal—

- cracking
- reduction in fracture toughness from thermal embrittlement
- loss of material
- loss of mechanical closure integrity

In Section 3.1.5 of the LRA, the applicant provides the results of its review of industry experience and NRC generic communications relative to the RCP components. The applicant states that the review ensured that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for RCP components at St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.5.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following aging management programs or activities that will be used to manage the aging effects applicable to the RCP components during the periods of extended operation:

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

3.1.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.5 and Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) of the RCP components will be maintained consistent with the CLB throughout the period of extended operation.

In Table 3.1-1 of the LRA, the applicant lists the RCP components that are within the scope of license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

3.1.5.2.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects applicable to the passive RCP components within the scope of license renewal—

- cracking due to flaw growth and stress corrosion in components that are fabricated from stainless steel and are exposed internally to primary treated water environments

- cracking and reduction in fracture toughness in components that are fabricated from stainless steel cast austenitic stainless steel and are exposed internally to primary treated water

- loss of material due to microbioloically influenced corrosion and pitting corrosion for the RCP lower seal heat exchanger that is exposed internally to other treated water

- loss of mechanical closure integrity in low-alloy steel bolting that is exposed externally either to containment air or to postulated leakage from the primary treated water environment (i.e., borated water leaks)

Fatigue. The RCP pressure boundary closure components may be susceptible to cracking induced by thermal fatigue. The applicant has evaluated the potential for these components to be degraded by thermal-fatigue-induced cracking as a TLAA for the components. The applicant's TLAA for the components is addressed in Section 4.3.1, "ASME Boiler and Pressure Vessel Code, Section III, Class I Components," of the LRA. The staff's evaluation of this TLAA is provided in Section 4.3 of this SER.

Aging of RCP Components Exposed to Internal Environments. Austenitic metals, including austenitic stainless steel, are known to be susceptible to stress corrosion cracking if the materials are exposed to the primary treated coolant (i.e., if the materials are known to be susceptible to PWSCC) or if the surface of the RCP component comes in contact with oxygenated liquids or liquids with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. In Table 3.1-1 of the LRA, the applicant has identified cracking as an applicable effect for the surfaces of RCP stainless steel and cast stainless steel components that are exposed to treated primary water. The applicant's identification of cracking in these components covers growth of pre-existing flaws and cracking induced by stress corrosion. This is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is therefore acceptable to the staff. As stated previously, cracking induced by thermal fatigue is addressed as a TLAA in the application (LRA Section 4.3.1), and is evaluated by the staff in Section 4.3.1 of this SER.

The applicant has stated that CASS components may be susceptible to loss of fracture toughness as a result of thermal aging. Thermal aging (thermal embrittlement) refers to the gradual and progressive changes in the microstructure and properties of a material due to exposure at elevated temperatures for an extended period of time. The applicant has identified that reduction of fracture toughness is an additional aging effect for the RCP components fabricated from CASS.[6] The applicant's identification of reduction of fracture toughness as an applicable effect for the CASS RCP components that are exposed to treated primary water is consistent with the staff's assessment in Section 3.1 of the SRP-LR, and is acceptable to the staff. The applicant proposed to use the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program to manage reduction of fracture toughness in the RCP components. The CASS reactor coolant pump casings and covers do not require an AMP to manage thermal embrittlement beyond the examinations programmatically required by ASME Section XI, as modified by Code Case N-481. This is consistent with the examination guidelines in the staff's

6 The other aging effect is cracking, which was assessed by the staff in the previous paragraph.

Interim Staff Guidance[7] on aging of RCP casings and covers fabricated from CASS and is therefore acceptable. The staff's evaluation of the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program is discussed in Section 3.0.5.3 of this SER.

The aging effects that can cause loss of material for the RCP lower seal heat exchanger are microbiologically influenced corrosion (MIC) and pitting corrosion. Loss of material due to MIC and pitting corrosion was identified by the applicant as an aging effect for the outside diameter of the RCP lower seal heat exchanger tubing. The applicant proposed to use the Chemistry Control Program to manage MIC and pitting corrosion of the RCP components. Based on the information provided above, the staff finds that the applicant adequately identified loss of material as an applicable aging effect of the RCP lower seal heat exchanger tubing, and that the Chemistry Control Program is acceptable to manage loss of material. The staff's evaluation of the Chemistry Control Program is discussed in Section 3.0.5.5 of this SER.

<u>Aging of RCP Components Exposed to External Environments</u>. The RCP bolting is made out of low-alloy steel (ferritic fasteners). These fasteners are stressed (preloaded) to ensure the integrity of the pressure boundary in RCP bolted connections. The applicant identified stress relaxation for RCP low-alloy steel components exposed to containment air as a potential mechanism that could result in a loss of mechanical closure integrity for these materials. This is a phenomenon in which the preloaded stress applied to the bolts for structural integrity loosens over time. This aging effect is consistent with the aging effects identified in Section IV.C2 of the GALL Report, Volume 2, for low-alloy steel bolting materials and is therefore acceptable to the staff.

The second mechanism that can lead to a loss of mechanical closure integrity for the low-alloy steel bolts is aggressive attack or corrosion as a result of exposure to potential leaks of the treated (borated) primary coolant. Industry experience and NRC generic communications have demonstrated that ferritic low-alloy steel materials may be extremely susceptible to loss of material/aggressive corrosive attack when exposed to borated water. Consistent with Section 3.1.5 of the LRA, the applicant's identification of loss of mechanical closure integrity for the low-alloy steel bolting materials covers this aging effect. This aging effect is consistent with the aging effects identified in Section 3.1 of the SRP-LR for low-alloy steel bolting materials and is therefore acceptable to the staff.

3.1.5.2.2 Aging Management Programs

The applicant indicated that the following existing and new programs will be used to manage the aging effects applicable to the RCP components for the extended periods of operation for the St. Lucie reactor units—

- the Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage cracking in RCP components that are fabricated from stainless steel (including CASS) and are exposed internally to primary treated water

7 Letter from C.I. Grimes (NRC) to D.J. Walters (NEI), License Renewal Issue No. 98-0030, "Thermal Embrittlement of Cast Austenitic Stainless Steel Components," Project No. 690, May 2000.

- the Chemistry Control Program to manage loss of material in RCP components that are fabricated from stainless steel and are exposed internally to other treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage reduction of fracture toughness in RCP components that are made from CASS and are exposed to primary treated water

- the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program to manage loss of mechanical closure integrity of material in low-alloy steel bolting that could be exposed to an external environment of containment air

- the Boric Acid Wastage Surveillance Program to manage loss of mechanical closure integrity of material in low-alloy steel bolting that could be exposed to postulated leaks of the primary treated water

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides a means of ensuring that the water quality is compatible with the materials of construction used in the RCP components and a mitigative means of minimizing loss of material and cracking in these components. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff's evaluation of this AMP is described in Section 3.0.5 of this SER.

Based on the interim staff guidance, the CASS RCP casings and covers do not require an AMP to manage thermal embrittlement beyond the examinations programmatically required by ASME Section XI, as modified by Code Case N-481. Accordingly, the applicant has proposed to use the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, as modified by Code Case N-481 (Section 3.2.2.1 of Appendix B to the LRA), to manage reduction of fracture toughness in RCP components fabricated from CASS. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program also manages aging effects applicable to specific Class 1, 2, and 3 component/commodity groups, including those passive RCP components identified in Table 3.1-1 of the application as being within the scope of license renewal. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) also manages loss of mechanical closure integrity in low-alloy steel bolting that could be exposed to containment air as identified in Table 3.1-1 of the application. This program manages aging effects applicable to specific Class 1, 2, and 3 components, including managing aging effects applicable to low-alloy steel bolting. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) manages loss of mechanical integrity in low-alloy steel bolting that is exposed to postulated leakage of the primary treated water from RCS. This program is consistent with the applicant's surveillance program that is, in effect, in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The staff evaluates this program in Section 3.0.5 of this SER.

3.1.5.3 Conclusion

The staff has reviewed the information in Section 3.1.5 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the St. Lucie RCP components. On the basis of this review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the RCP components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6 Steam Generators

The applicant describes its AMR of the steam generators in LRA Section 3.1.6, "Steam Generators." The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the steam generators will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The nuclear steam supply system in St. Lucie Units 1 and 2 uses steam generators to transfer the heat generated in the reactor coolant system to the secondary system. The steam generator is a vertical U-tube heat exchanger with the reactor coolant on the tube side and the secondary fluid on the shell side. Reactor coolant enters the steam generator through the inlet nozzle, flows through tubes, and leaves through two outlet nozzles. Divider plates in the lower head of the steam generators separate the inlet and outlet plenums. The plenums are a carbon steel forging with stainless steel clad; the reactor coolant side of the tubesheet is cladded with nickel-chromium-ferrite alloy. The tube ends are welded on the primary side of the tubesheet, and the tube inside the tubesheet bore is expanded to form an interference fit to resist tube pullout. Feedwater enters the steam generator shell side through the feedwater nozzle where it is distributed via a feedwater distribution ring which directs flow to the downcomer in the steam generators. The downcomer is the annular passage formed by the inner surface of the steam generator shell and the cylindrical shell which encloses the tube bundle. Upon exiting from the bottom of the downcomer, the secondary flow is directed upward over the vertical tube bundle. Heat transferred from the primary side converts a portion of the secondary flow into steam. A saturated steam/water mixture enters the moisture separator section in the top of the steam generator where the water is removed from the mixture and dried in the evaporator. Dry steam exits the steam outlet nozzle and is piped to the turbines.

St. Lucie Unit 1 has two replacement steam generators manufactured by Babcock and Wilcox International which were installed in December 1997. The replacement steam generators include design features and materials that minimize potential corrosion and cracking. For example, the tube is fabricated with thermally treated Alloy 690 material which has better corrosion resistance than the mill-annealed Alloy 600 material used in the original steam generators. The tube is supported by the stainless steel lattice bars which reduce corrosion at the tube support intersections. The hydraulic expansion joints are installed full length in the tubesheet to minimize crevice corrosion and cracking in the tubesheet. In addition, the replacement steam generator (RSG) design addresses industry feedwater distribution system problems such as waterhammer, thermal stratification, erosion, and internal feedwater header collapse. The RSG distribution system satisfies all the current (at the time of design) NRC recommendations with respect to waterhammer, provides flow stratification mitigation, and addresses industry concerns regarding corrosion, corrosion cracking, thermal fatigue, and material erosion. Furthermore, the RSG allows for inspection access to the feedwater header region through tunnels and ladders at each drum manway location.

St. Lucie Unit 2 has two original Combustion Engineering model 3410 steam generators that have tubes fabricated from the mill-annealed Alloy 600 material. The tube is supported by the carbon steel lattice bars. The tube is also hydraulically expanded in the tubesheet to minimize crevice corrosion. The detailed description of the steam generators are provided in Unit 1 UFSAR, Section 5.5.1 and Unit 2 UFSAR, Section 5.4.2. The staff's review of the applicant's scoping results of the steam generator components is provided in Section 2.3.1.6 of this SER.

3.1.6.1 Summary of Technical Information in the Application

In Section 3.1.6 and Table 3.1-1 of the LRA, the applicant identified that the steam generator components are fabricated from carbon steel, stainless steel, low-alloy steel, low-alloy steel and carbon steel with stainless steel cladding, low-alloy steel with Alloy 600 cladding, and Alloy 600/690. In Table 3.1-1 of the LRA, the applicant identified that the steam generator components are exposed internally to primary and secondary treated water and externally to containment air and borated water leaks. The applicant defined these internal and external environments in Tables 3.0-1 and 3.0-2 of the LRA respectively.

As stated in the St. Lucie UFSARs, the steam generators in both St. Lucie units are designed and fabricated in accordance with Section III of the ASME Boiler and Pressure Vessel Code specifications. The steam generator components, their intended functions, the materials of construction, and environments are described in Table 3.1-1 of the LRA. The steam generator intended functions include pressure boundary integrity, heat transfer, flow distribution, structural support, and throttling. The inside surface of the primary and secondary side of the steam generators is exposed to an internal environment of treated water. The outside surface of the steam generators is exposed to external environments of containment air and potential borated water leaks. The materials of construction of the steam generator components include stainless steel, low-alloy steel, carbon steel, Alloy 600, and Alloy 690.

The applicant stated that the St. Lucie Units 1 and 2 steam generator designs do not include the feedwater impingement plates and supports and tube support plates. Also, feedwater inlet rings and supports will not require an aging management review because these components do not perform or support any license renewal system intended functions that satisfy the scoping criteria of 10 CFR 54.4 and therefore are not within the scope of license renewal.

3.1.6.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identified cracking, loss of material, and loss of mechanical closure integrity as the aging effects on steam generator components that require aging management during the period of extended operation.

<u>Cracking</u>. The applicant stated that industry experience has shown that Alloy 600 steam generator tubing is susceptible to PWSCC, secondary side intergranular attack (IGA), and intergranular stress corrosion cracking (IGSCC). Stress corrosion cracking (SCC) is localized and caused by a combination of stress, susceptible material, and an aggressive environment. The applicant identified cracking caused by flaw growth and stress corrosion as an aging effect requiring management for the period of extended operation. Growth of original manufacturing flaws over time due to service loading can also cause cracking. The applicant stated that for the replacement steam generators, 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, the applicant prevents sensitized stainless steels from coming in contact with an aggressive environment at the St. Lucie Nuclear Plant.

Industry operating experience has shown 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. Cracking caused by fatigue is identified as a TLAA and is addressed in Subsection 4.3.1 of the LRA.

Industry experience has also shown 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, two cases of leaking tube plugs were recorded, both in the original Unit 1 steam generators in 1996. In Unit 2, one of the welded shop plugs was replaced in 1985 due to leakage. The applicant has considered PWSCC to be an aging effect that requires management for the tube plugs.

The applicant stated that steam generator primary instrument nozzles, fabricated from Alloy 600, have not exhibited aging effects caused by PWSCC. This can be attributed to their exposure to lower temperatures during normal power operation when compared to the pressurizer and RCS hot-leg instrument nozzles and reactor vessel upper head control rod drive mechanism housing tubes. The applicant stated that it appears that PWSCC of the Alloy 600 instrument nozzles on steam generators is not likely to be significant during the period of extended operation. However, since Alloy 600 in general is susceptible to PWSCC, the applicant has considered PWSCC to be an aging effect requiring management for the primary instrument nozzles on steam generators.

Loss of Material. The applicant identified loss of material as an aging effect for the steam generators requiring management during 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.

The applicant identified general corrosion, pitting corrosion, and crevice corrosion as aging mechanisms for internal surfaces of carbon steel and low-alloy steel components on the steam generator secondary side. These degradations on the secondary-side surfaces are mitigated by maintaining adequate secondary-side chemistry controls.

The applicant stated that pitting of the secondary side of the 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 because of the low amount of copper and chlorides in the secondary system, careful control of the oxidizing in the secondary water, and routine removal of tubesheet sludge via lancing.

The applicant identified flow-accelerated corrosion as a potential aging mechanism for loss of material in nozzles and safe-ends of feedwater, steam outlet, and blowdowns, and carbon steel tube support lattice bars (Unit 2 only). Although neither the industry nor the St. Lucie plant-specific operating experience includes any reports of loss of material in steam generator feedwater, steam outlet, or blowdown nozzles and safe-ends, they are exposed to conditions conducive to flow-accelerated corrosion and are considered for aging management.

The applicant identified loss of material caused by tube wear at contacts with tube support straps. Therefore, tube wear is an aging mechanism that requires management. The applicant also identified loss of material caused by aggressive chemical attack as an aging effect requiring management for external surfaces of carbon steel components exposed to borated water leaks.

Loss of Mechanical Closure Integrity. The applicant identified loss of mechanical closure (bolting) integrity as an aging effect that requires aging management. Loss of mechanical closure integrity can result from stress relaxation and/or aggressive chemical attack. The applicant stated that loss of mechanical closure integrity due to aggressive chemical attack has been observed in the industry and is the most common aging effect of concern for ferritic fasteners.

In accordance with Section 3.1.6 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the steam generators and associated components to ensure that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for St. Lucie. This review also included the plant-specific operating experience at both subject plants.

3.1.6.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identified the following six AMPs to manage the above aging effects associated with the steam generator components:

- 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
- Alloy 600 Inspection Program

The applicant concluded that these AMPs will manage the effects of aging associated with the steam generator components such that the intended functions of the steam generator components will be maintained consistent with the CLB under all design loading conditions during the period of extended operation.

The applicant addressed cracking caused by fatigue of steam generator components as a TLAA item which is addressed in Section 4.3.1 of the LRA. The staff has evaluated the aging management of the metal fatigue issue as a part of the TLAA review in Section 4.3 of this SER.

3.1.6.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.6 and Table 3.1-1 of the LRA, pertinent sections of Appendices A and B to the LRA, and the September 26, 2002, response to the staff's request for additional information regarding the applicant's demonstration that the effects of aging associated with the steam generator components will be adequately managed so that there is reasonable assurance that the intended functions of the steam generator components will be maintained consistent with the CLB throughout the period of extended operation.

Specifically, the staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management programs for the steam generator components in Section 3.1.6 and Table 3.1-1 of the LRA. Table 3.1-1 of the LRA lists the steam generator components that are within the scope of the license renewal and identifies the aging effects that require management.

3.1.6.2.1 Aging Effects

The staff finds that the aging effects identified in Section 3.1.6 and Table 3.1-1 of the LRA are acceptable because they are consistent with previously accepted staff positions. However, the staff raised several questions regarding certain aging effects associated with the aging management programs.

The staff noted that in Table 3.1-1 of the LRA, the applicant specified that the external surface of the primary instrument nozzles will be in the leaking borated water environment. However, there was no aging effect and associated aging management program identified for the primary instrument nozzles in this external environment. The applicant responded that the primary instrument nozzles are fabricated from either Alloy 600 or Alloy 690 material. Alloy 600 and 690 are nickel-based alloys, which are not susceptible to boric acid wastage. As such, there is no aging effect requiring management for the primary instrument nozzles exposed to an external environment of borated water leaks. The staff noted that the applicant has identified the Alloy 600 Inspection program, Chemistry Control Program, and ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program to manage PWSCC of the primary instrument nozzles. Under the inspection AMPs, the staff believes that any potential degradation occurring at the primary instrument nozzles caused by borated acid corrosion could be detected and repaired, if necessary. The staff finds this issue closed.

The staff requested clarification on why loss of material due to boric acid corrosion (on the external surface) was not an aging effect identified for the secondary manway and handhole closure covers, shell assembly, feedwater nozzles and safe-ends, steam outlet nozzles and safe-ends, and primary heads. The applicant responded that the primary heads are potentially exposed to an external environment of borated water leaks. Accordingly, loss of material is identified as an aging effect requiring management, and the Boric Acid Wastage Surveillence Program provides assurance that this aging effect is managed for the period of extended operation. The steam generator secondary manway and handhole closure covers, shell assemblies, feedwater nozzles and safe-ends, and steam outlet nozzles and safe-ends are not considered to be susceptible to borated water leaks since they are isolated from potential RCS leaks by the steam generator geometry. The geometry of the steam generator primary head and the physical distance between the primary manways and the upper and lower shells essentially eliminate the potential for boric acid exposure to these parts. The staff finds that the applicant’s conclusion that loss of material due to boric acid corrosion is not an aging effect for the aforementioned components is acceptable because these components are isolated from potential RCS leaks and, therefore, potential for loss of material due to boric acid exposure is eliminated.

The staff noted that in Table 3.1-1 of the LRA, cracking was identified as an aging effect for Unit 1 stainless steel tube support lattice bars, but cracking was not identified as an aging effect for Unit 2 carbon steel tube support lattice bars. The staff requested the applicant to clarify why cracking is not applicable to the Unit 2 tube support lattice bars. The applicant stated that carbon steel components are not considered to be susceptible to cracking in a secondary-side treated water environment. As such, cracking is not identified as an aging effect requiring management for the St. Lucie Unit 2 carbon steel tube support lattice bars. The staff noted that in Section 3.1.6 of the LRA, the applicant has identified loss of material caused by flow-accelerated corrosion for the carbon steel tube support lattice bars in Unit 2 steam generators. The applicant has identified the Steam Generator Integrity Program to manage the corrosion of the tube support lattice bars. Specifically, the applicant credits periodic tube bundle flushing to minimize flow-accelerated corrosion of the lattice bars as discussed in Section 3.1.6.2.2 of this SER. The staff finds this issue closed because the applicant has identified the Steam Generator Integrity Program to manage degradation in the tube support lattice bars in the Unit 2 steam generators.

The staff requested the applicant to clarify why wall thinning attributable to erosion was not applicable as an aging effect for the secondary manways and handholes. The applicant stated that the design of the secondary manways and handholes precludes the potential for wall thinning due to erosion. The secondary manways and handholes are located in areas of large cross section where velocity is low and erosion is not an aging concern. Plant-specific experience has confirmed that these components are not susceptible to this aging effect. The staff agrees with the applicant's conclusion because the location of the manways and handholes precludes wall thinning in these components.

In NRC Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Welds in Steam Generators," the staff states that if general corrosion or pitting of the steam generator shell is known to exist, the inspection program in Section XI of the ASME Code may not be sufficient to differentiate isolated cracks from inherent geometric conditions of the shell. The staff requested the applicant to describe additional inspection procedures for the upper and lower steam generator shells, if general corrosion or pitting exists in the St. Lucie steam generator shells. The applicant responded that, as indicated in Section 3.1.6.2.2 and Table 3.1-1 of the LRA, loss of material due to general corrosion and pitting corrosion has been identified as an aging effect for internal surfaces of carbon steel and low-alloy steel components on the steam generator secondary side, including the upper and lower shells. General corrosion and pitting corrosion of the steam generator upper and lower shells are mitigated by maintaining adequate secondary-side chemistry controls via the Chemistry Control Program. To date, loss of material due to general corrosion and pitting corrosion of the St. Lucie Units 1 and 2 steam generator upper and lower shells has not been experienced. Accordingly, no additional inspection procedures are required at this time. The staff considers this issue closed.

The staff requested the applicant to provide information on the tube plugs installed in the Unit 1 and 2 steam generators, such as plug type and operating experience. The applicant responded that the replacement steam generators use mechanical tube plugs fabricated from thermally treated Alloy 690 material. To date, there has been no evidence of tube plug degradation and no tube plugs have been replaced in the Unit 1 replacement steam generators. The St. Lucie Unit 2 steam generators use a combination of welded plugs and hydraulically expanded plugs. All hydraulically expanded tube plugs currently installed in the St. Lucie Unit 2 steam generators are fabricated from thermally treated Alloy 690 material. Approximately 50 tubes in the Unit 2 steam generators were plugged during manufacture (i.e., shop plugs) with welded tube plugs fabricated from Alloy 600 material. One of these welded shop plugs was replaced in 1985 due to leakage. In the UFSAR, the applicant stated that should unacceptable tube degradation occur, the integrity of the reactor coolant boundary may be restored by installing a tube plug within the tube or tubesheet hole if removal of the tube is warranted. Should tube degradation occur that indicates the potential for tube severance, the tube may have a stake and tube plug installed. If the plugged tube severs, the stake is designed to reduce the possibility of tube-to-tube contact. The stakes, the plugs, and their installation are designed to function under all operating, transient, or test conditions of the steam generator. This installation takes into consideration maintaining integrity under vibrating loads and material compatibility with tube material subject to both reactor coolant and feedwater system environments. As a result of the staff request for additional information, the applicant revised Table 3.1-1 of the LRA to include Alloy 600 as a material for fabrication of tube plugs. The staff notes that the aging effect related to the tube plugs will be managed under the Steam Generator Integrity Program. The staff finds the tube plug issue closed.

On the basis of the staff's review, the staff concludes that the applicant has identified all appropriate aging effects applicable to the steam generator components.

In addition, in Table 3.1-1 of the LRA, the applicant identified only thermally treated Alloy 690 as the material for tube plugs. The staff questioned the applicant regarding other material that were used in tube plug fabrication.

3.1.6.2.2 Aging Management Programs

The applicant indicated six AMPs as discussed in Section 3.1.6.1.2 of this SER. Of the six, the Steam Generator Integrity Program is a system-specific AMP and evaluated in Section 3.1.0.4 of this SER. The other five are common AMPs and are evaluated separately in Section 3.0.5 of this SER.

The Chemistry Control Program (Section 3.2.5 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used for the steam generator components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The applicant stated that the Chemistry Control Program provides assurance that pitting corrosion, general corrosion, crevice corrosion, PWSCC, IGA, and IGSCC are managed and that the intended functions of the steam generators will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation. The staff's evaluation of this AMP is described in Section 3.0.5.5 of this SER.

The ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program (Section 3.2.2.1 of Appendix B to the LRA) manages aging effects of loss of material, cracking, gross loss of preload, and reduction in fracture toughness. The scope of the Inservice Inspection Program for Class 1 and Class 2 components complies with the requirements of ASME Section XI, Subsections IWB, IWC, and IWD. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. ASME Section XI inservice inspections of components are intended to detect significant flaw growth. These inspections provide assurance that significant flaws do not exist or that a large flaw subject to crack growth would be detected so that it could be characterized, evaluated, and repaired. Continued performance of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides assurance that degradation in the steam generator components caused by pitting corrosion, general corrosion, crevice corrosion, PWSCC, IGA, and IGSCC is managed and that the intended functions of the steam generator components will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation. The staff's evaluation of this AMP is described in Section 3.0.5.3 of this SER.

The Flow Accelerated Corrosion Program (Section 3.2.9 of Appendix B to the LRA) is designed to manage loss of material from the carbon steel components due to 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, blowdown nozzles and safe-ends, and Unit 2 carbon steel tube support lattice bars is managed and that the intended functions of the steam generators will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation. The staff's evaluation of this AMP is described in Section 3.0.5.8 of this SER.

The Boric Acid Wastage Surveillance Program (Section 3.2.4 of Appendix B to the LRA) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of reactor coolant piping and associated components, and specifically for those made of carbon steel or low-alloy steel. The Boric Acid Wastage Surveillance Program provides assurance that the aging effect of loss of mechanical closure integrity due to aggressive chemical attack is managed and that the intended functions of the steam generators will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation of this AMP is described in Section 3.0.5.4 of this SER.

The Alloy 600 Inspection Program (Section 3.2.1 of Appendix B to the LRA), in conjunction with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Chemistry Control Program, provides assurance that potential PWSCC in the primary instrument nozzles on the steam generators is managed and that the intended function of the primary instrument nozzles will be maintained consistent with the St. Lucie Units 1 and 2 CLB for the period of extended operation. The staff's evaluation of this AMP is described in Section 3.1.0.1 of this SER.

3.1.6.3 Conclusion

The staff has reviewed the information in Section 3.1.6 and Table 3.1-1 of the LRA, as it relates to the applicant's AMRs for the RCP components. On the basis of this review, with the exception of open items 3.0.2.2-1, 3.1.0.1-1, and 3.1.0.1-2, the staff concludes that the applicant has demonstrated that the aging effects associated with the steam generator components will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Engineered Safety Features Systems

In Section 3.2, “Engineered Safety Features Systems,” of the license renewal application (LRA), the applicant describes the AMR for the engineered safety features (ESF) systems. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the ESF systems. The staff reviewed Section 3.2 and the applicable portions of Appendices A, B, and C to determine whether the applicant provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3) for the ESF systems' structures and components that are determined to be within the scope of license renewal and subject to an AMR.

The ESF systems include the following:

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

In Section 2.3.2 of the LRA, the applicant describes these systems and identifies the components requiring an AMR for license renewal. The staff's evaluation of the scoping methodology and the ESF systems' structures and components included within the scope of license renewal and subject to an AMR is documented in Sections 2.1 and 2.3.2, respectively, of this SER. In LRA Appendix A, “Updated Final Safety Analysis Report Supplement,” the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). In LRA Appendix B, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In LRA Appendix C, the applicant describes the process used to identify many of the applicable aging effects for the SCs that are subject to an AMR. In LRA Appendix D, the applicant states that no changes to the St. Lucie Technical Specifications have been identified. A review of each of these ESF systems follows.

3.2.1 Containment Cooling System

3.2.1.1 Technical Information in the Application

Section 2.3.2.1 of the LRA describes the containment cooling system as being designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a design basis event. 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 atmosphere. Heat removed from the containment is transferred to component cooling water. Containment cooling consists of four fan cooling units that are located outside the secondary shield wall inside each containment.

Containment cooling system components subject to an AMR include fan cooler housings and valves (pressure boundary only), heat exchangers, ducts, thermowells, flexible connections, drip pans, piping, and fittings. The intended functions of these containment cooling components include pressure boundary integrity and heat transfer. A complete list of containment cooling components requiring an AMR, the components' intended functions, and the applicable AMPs is provided in Table 3.2-1 of the LRA.

3.2.1.1.1 Aging Effects

In Table 3.2-1 of the LRA, the applicant identifies stainless steel, carbon steel, copper, copper nickel, rubber-coated cloth, and galvanized carbon steel as the materials of construction for the containment cooling system components. Loss of material was identified as an applicable aging effect for carbon steel, copper, stainless steel, copper nickel, and galvanized carbon steel. Fouling was identified as an applicable aging effect for copper. Cracking was identified as an applicable aging effect for rubber-coated cloth. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel bolting (mechanical closure).

Austenitic stainless steel and galvanized carbon steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, no aging effects were identified for the surfaces of stainless steel thermowells (including drip pan thermowells), as well as ducts made of galvanized carbon steel, in air/gas or containment air environments.

Loss of material of carbon steel materials may occur in moist air environments. The applicant identified loss of material as an aging effect on the carbon steel containment fan cooler housings, valves, piping/fittings, Unit 1 containment fan cooler heat exchanger stubs/flanges, and containment fan cooler motor heat exchanger headers (Unit 1 only).

Copper material in contact with treated water may be susceptible to fouling, which if unattended, has the potential to block the flow of coolant through the tubes, and thereby compromise the components' heat transfer function. The applicant identified the aging effect of fouling for the copper containment fan cooler heat exchanger tubes and containment fan cooler motor heat exchanger tubes (Unit 1 only), in an internal treated water – other environment.

Components made of copper, copper nickel, stainless steel, and carbon steel components are susceptible to loss of material in a treated water – other environment. The applicant identified loss of material as an aging effect for the copper containment fan cooler heat exchanger headers and end caps, stainless steel containment fan cooler heat exchanger vent plugs, Unit 1 carbon steel and Unit 2 copper nickel containment fan cooler heat exchanger stubs/flanges, Unit 2 carbon steel containment fan cooler closed cooling water system flanges, copper containment fan cooler motor heat exchanger tubes (Unit 1 only), carbon steel containment fan cooler motor heat exchanger headers (Unit 1 only), and carbon steel piping fittings.

Stainless steel material may be susceptible to loss of material when exposed to raw water drains. The applicant identified the aging effect of loss of material with the stainless steel drip pans. The applicant also identified cracking as the aging effect for the flexible connections made of rubber-coated cloth in air/gas environments.

Loss of material of carbon steel components may result from contact with borated water leaks. The applicant identified loss of material for carbon steel containment fan cooler housings, Unit 1 containment fan cooler heat exchanger stubs/flanges, containment fan cooler motor heat exchanger headers (Unit 1 only), valves (Unit 1 only), and piping/fittings when exposed to borated water leaks. The applicant similarly identified the aging effect of loss of material for the galvanized carbon steel ducts which is exposed to borated water leaks.

Loss of material of copper and copper nickel by corrosion may occur in a moist air environment in the containment building. The applicant, therefore, identified loss of material as an aging effect for the containment fan cooler heat exchanger with copper tubes, fins, headers and end caps in Unit 2. The applicant identified loss of material in a treated water environment for copper and copper nickel in containment fan cooler heat exchanger header, and cap and stubs/flanges in both units, and for containment fan cooler heat exchanger copper tubes in Unit 1 only. The applicant identified the aging effect of loss of material in the stainless steel containment fan cooler heat exchanger vent plugs and frame side plates which are exposed to a containment air (wetted) environment.

Loss of mechanical closure integrity of carbon steel bolting may be caused by borated water leaks from other plant systems. The applicant identified this aging effect for the carbon steel bolting (mechanical closure) which is exposed to a borated water leak environment.

3.2.1.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment cooling system:

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the containment cooling system will be adequately managed by these AMPs during the period of extended operation.

3.2.1.2 Staff Evaluation

In Section 2.3.2., Section 3.2, and Table 3.2-1 of the LRA, the applicant describes its AMR of the containment cooling system for license renewal. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment cooling system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.1.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.1, Table 3.2-1, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In Table 3.2-1 of the LRA, the applicant identifies no aging effects requiring management of carbon steel bolting exposed to containment air environments. By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects on closure bolting, of auxiliary system, exposed externally to outdoor, indoor not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved. The staff considers that the applicant's response to RAI 3.3-1 addresses the similar concern for the closure bolting of the ESF systems as well, because of the similar material/environment combination.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment cooling system's structures or components with the environments described in Section 2.3.2.1 and Table 3.2-1 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.1.2.2 Aging Management Programs

In Table 3.2-1 of the LRA, the applicant credited the following AMPs for managing the aging effects in the containment cooling system:

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material and fouling associated with the copper containment fan cooler heat exchanger headers and end caps, Unit 1 carbon steel containment fan cooler heat exchanger stubs/flanges, Unit 2 carbon steel containment fan cooler closed cooling water flanges, carbon steel Containment fan cooler motor heat exchanger headers, and carbon steel piping/fittings, exposed to treated water–other environments.

The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material associated with the carbon steel containment fan cooler housings, copper containment fan cooler heat exchanger tubes, copper containment fan cooler heat exchanger fins, containment fan cooler heat exchanger headers and caps, Unit 2 copper nickel containment fan cooler heat exchanger stubs/flanges, carbon steel valves, and piping/fittings, which are exposed to the containment air (wetted). The Boric Acid Wastage Surveillance Program will be used to manage loss of material associated with the carbon steel components of containment fan coolers housing and heat exchangers; carbon steel valves, piping/fittings, and bolting; and galvanized carbon steel ducts, which are exposed to borated water leaks. In addition, the Systems and Structures Monitoring Program will be used to manage the cracking associated with the flexible connections made of rubber-coated cloth.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-1, the staff concludes that the AMPs identified above will adequately manage the aging effects of the containment cooling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.3 Conclusion

The staff has reviewed the information in Section 2.3.2.1 and Table 3.2-1 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, With the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment cooling system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing aging effects as required by 10 CFR 54.21(d).

3.2.2 Containment Spray System

3.2.2.1 Technical Information in the Application

In Section 2.3.2.2 of the LRA, the applicant describes the containment spray system as being designed to remove sufficient heat to maintain the containment below its structural design pressure and temperature limits following a design basis event. The containment spray system for each unit consists of two containment spray pumps that take suction from the refueling water tanks and spray borated water from nozzles located near the top of each containment structure. When the refueling water tank inventory is exhausted, the containment spray pump suction is switched to the containment recirculation sumps, and the shutdown cooling heat exchangers are used to remove heat from the recirculation water.

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

Containment spray components subject to an AMR include refueling water tanks, sodium hydroxide tank, hydrazine tank, pumps and valves (pressure boundary only), heat exchangers, eductors, orifices, strainers, thermowells, spray nozzles, vortex breaker (Unit 1 only), rupture discs, sightglasses, piping, tubing, and fittings. The intended functions of 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 AMR, the component's intended functions, and the applicable AMPs is provided in Table 3.2-2 of the LRA.

3.2.2.1.1 Aging Effects

In Table 3.2-2 of the LRA, the applicant identifies aluminum, fiberglass-reinforced vinyl ester, stainless steel, cast iron, brass, nickel alloy, carbon steel with stainless steel cladding, glass, and carbon steel as the materials of construction for the containment spray system components. Loss of material was identified as an applicable aging effect for aluminum, stainless steel, cast iron, brass, and carbon steel. Cracking and delamination (including loss of adhesion) were identified as applicable aging effects for fiberglass-reinforced vinyl ester. Fouling was identified as an applicable aging effect for stainless steel. Cracking was identified as an applicable aging effect for stainless steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Aluminum material is designed to be corrosion resistant in dry air environments. Corrosion and cracking generally have not been a problem for aluminum or for stainless steel components in the dry or moist environments. No aging effects were identified for the Unit 1 aluminum refueling water tank exposed to air/gas environments.

No aging effects were identified for the stainless steel components, such as the Unit 2 refueling water tank, NaOH storage tank (Unit 1 only), hydrazine storage tank (Unit 2 only), sodium hydroxide tank rupture disc (Unit 1 only), valves, piping/fittings and tubing/fittings, spray nozzles, containment spray pumps, eductors (Unit 1 only), hydrazine pumps (Unit 2 only), thermowells, rupture disc, orifices, and bolting (mechanical closure), which are exposed to air/gas, containment air, indoor not-air-conditioned, and outdoor environments.

Loss of material from corrosion can occur when stainless steel materials are in contact with raw water. However, if the raw water is well drained, stainless steel materials would not be susceptible to corrosion. Therefore, no aging effects were identified for the valves and piping/fittings which are part of the reactor cavity sump drains. Similarly, no aging effects were identified for nickel alloy piping exposed to raw water-drains or air/gas environments. Carbon steel with stainless steel cladding and glass are not susceptible to corrosion in treated water–other or air/gas environments. No aging effects were identified for sightglass (Unit 1 only) when exposed to these environments.

Brass material generally has not been a problem in indoor not-air-conditioned environments. No aging effects were identified for the containment spray pump cooler flex connectors (Unit 1 only) exposed to indoor not-air-conditioned environments. Similarly, no aging effects were identified for the bolting (mechanical closure) exposed to indoor not-air-conditioned, containment air, and outdoor environments.

Loss of material of aluminum materials from general corrosion may occur when in contact with treated water-borated environments. The applicant identified loss of material for the aluminum portion of the Unit 1 refueling water tank, which is exposed to treated water-borated environments. The applicant also identified the aging effects of cracking and delamination for the fiberglass portion of the Unit 1 refueling water tank, when exposed to treated water-borated environments.

Loss of material and cracking of stainless steel in a treated water environment are possible aging effects under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low-flow conditions could lead to loss of material and cracking of stainless steel in treated water. The applicant identified the aging effects of loss of material for the Unit 2 stainless steel refueling water tank, containment spray pumps, eductors (Unit 1 only), orifices, and refueling water tank strainers, which are exposed to treated water-borated environments. For the same treated water environment and an elevated temperature in excess of 140 °F, the applicant also identified the aging effects of loss of material and cracking for the stainless steel valves, piping/fittings, tubing/fittings, and thermowells. For containment spray pump cooler tubes exposed to treated water environments, the tubes may be susceptible to fouling, which if unattended, has the potential to block the flow of coolant through the tubes and in some cases to produce corrosive environments that could lead to a loss of tube material. The applicant identified the aging effects of loss of material and fouling for the stainless steel containment spray pump cooler tubes, which are exposed to a treated water-borated environment for the inside diameter and a treated water–other environment for the outside diameter.

Cast iron, brass, and aluminum are susceptible to loss of material when exposed to a treated water environment. The applicant identified the aging effect of loss of material for cast iron containment spray pump cooler shells (Unit 1 only) and brass containment spray pump cooler flex connectors (Unit 1 only), which are exposed to treated water–other environments and for the aluminum refueling water tank vortex breaker (Unit 1 only), which is exposed to a treated water-borated environment.

Loss of material of aluminum materials by corrosion may occur in a moist air environment. The applicant identified the aging effect of loss of material for the Unit 1 refueling water tank exposed to the outdoor environment. Cast iron material may be susceptible to loss of material in an indoor not-air-conditioned or a borated water leaks environment. The applicant identified the aging effect of loss of material for the containment spray pump cooler shells (Unit 1 only) which are exposed to these environments.

Plant experience has identified the potential for SCC and loss of material due to pitting corrosion on stainless steel components located in the emergency core cooling system (ECCS) pipe tunnel. The applicant identified the aging effect of loss of material for the piping/fittings which are located in the outdoor ECCS pipe tunnel.

Carbon steel components are susceptible to loss of material due to boric acid corrosion of external surfaces. The applicant identified the aging effect of loss of material for the carbon steel sightglass (Unit 1 only), which is exposed to an indoor not-air-conditioned or a borated water leaks environment. Finally, loss of mechanical closure integrity of carbon steel bolting may be caused by borated water leaks from other plant systems. The applicant identified this aging effect for the carbon steel bolting (mechanical closure) that is exposed to a borated water leaks environment.

3.2.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment spray system:

- Periodic Surveillance and Preventive Maintenance Program

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the containment spray system will be adequately managed by these AMPs for the period of extended operation.

3.2.2.2 Staff Evaluation

In Section 2.3.2.2, Section 3.2, and Table 3.2-2 of the LRA, the applicant describes its AMR of the containment spray system for license renewal. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment spray system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.2, Table 3.2-2, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant in order to complete the review. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

In Table 3.2-2 of the LRA, the applicant states that stainless steel and glass in a sodium hydroxide (NaOH) environment were determined to have no aging effects requiring management. In RAI 3.2-1, the staff requested the applicant to justify its conclusion that no aging effects were associated with stainless steel and glass in an environment of hydrazine or NaOH. In its response, L-2002-157, dated September 26, 2002, the applicant cited the *Metals Handbook*, 9^{th} Edition, Volume 13, and *National Association of Corrosion Engineers Corrosion Data Survey*, 5th Edition, as references. The applicant states that the *Metals Handbook* shows a negligible corrosion rate (i.e., less than 0.1 mils/year) for stainless steel in the sodium hydroxide (NaOH) environment applicable to St. Lucie Unit 1 containment spray components (i.e., 28.5–30.5 percent by weight solution NaOH and maximum temperature of 100 °F). Additionally, the potential for SCC in an NaOH environment is avoided by maintaining temperatures below 200 °F. The applicant states that since the operating temperature of the components exposed to the NaOH internal environment is a maximum of 100 °F, there are no aging effects requiring management for these components. Similarly, the applicant states that based on the *National Association of Corrosion Engineers Corrosion Data Survey*, the corrosion rate is negligible for stainless steel in the hydrazine environment applicable to St. Lucie Unit 2 containment spray components (i.e., 25.4 percent by weight solution hydrazine and normal operating temperature of less than 100 °F). The applicant also states that these conclusions are supported by plant-specific operating experience, in that neither stainless steel nor glass in the environments of hydrazine or sodium hydroxide have experienced any adverse aging effects.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily revolves this issue because the applicant has provided sufficient evidence to demonstrate that stainless steel and glass are not subject to significant aging degradation in an environment of hydrazine or NaOH.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the containment spray system SSCs to the environments described in Section 2.3.2.2 and Table 3.2-2 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.2.2.2 Aging Management Programs

In Table 3.2-2 of the LRA, the applicant credits the following AMPs for managing the aging effects in the containment spray system:

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material for the Unit 1 aluminum refueling water tank exposed to treated water-borated and for the Unit 1 cast iron containment spray pump cooler shells and the brass containment spray pump cooler flex connectors exposed to treated water-other.

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be used to manage cracking and delamination for the portion of Unit 1 refueling water tank made of fiberglass-reinforced vinyl ester exposed to treated water-borated. The Chemistry Control Program will be used to manage loss of material for the stainless steel containment spray pumps, Unit 2 refueling water tank, eductors, Unit 1 aluminum refueling water tank vortex breaker, stainless steel orifices, and the stainless steel refueling water tank strainers, all exposed to treated water-borated.

The Chemistry Control Program will be used to manage loss of material and fouling for the Unit 1 stainless steel containment spray pump cooler tubes exposed to either treated water-borated (inside diameter) or treated water-other (outside diameter). The Chemistry Control Program will also be used to manage loss of material and cracking for the stainless steel valves, piping/fittings, tubing/fittings, and thermowells exposed to treated water-borated environments.

The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material for the Unit 1 aluminum refueling water tank exposed to an outdoor environment. The

Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material and cracking for the stainless steel piping/fittings exposed to an outdoor (ECCS pipe tunnel) environment. The Systems and Structures Monitoring Program will be used to manage loss of material for the Unit 1 cast iron containment spray pump cooler shells and the Unit 1 sightglass (carbon steel) exposed to indoor not-air-conditioned environment. In addition, the Boric Acid Wastage Surveillance Program will be used to manage loss of material for the Unit 1 cast iron containment spray pump cooler shells and Unit 1 sightglass (carbon steel) exposed to borated water leaks.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-2, the staff concludes that the AMPs identified above will effectively manage the aging effects of the containment spray system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3 Conclusion

The staff has reviewed the information in Section 2.3.2.2 and Table 3.2-2 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment spray system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of and confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment spray system as required by 10 CFR 54.21(d).

3.2.3 Containment Isolation System

3.2.3.1 Technical Information in the Application

In Section 2.3.2.3 of the LRA, the applicant describes the containment isolation system as being designed to provide for the closure or integrity of containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment. The AMR results included here are for those process systems whose only license renewal system intended function is containment isolation. Process systems that have license renewal system intended functions in addition to the containment isolation function are included in the system AMR results described elsewhere in Sections 3.1, 3.2, 3.3, and 3.4. The pressure boundary (metallic) portions of electrical penetrations and miscellaneous/spare mechanical penetrations that are not associated with a process system are included in the civil/structural AMR results described in Section 3.5. The non-metallic and conductor portions of containment electrical penetrations are included in the electrical system AMR results described in Section 3.6. It is noted that an AMR was performed for all containment penetrations and associated containment isolation valves and components that ensure containment integrity, regardless of where they are described. Therefore, included in this evaluation are containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief. The containment vacuum relief is an exception, since its additional function is to protect the containment vessels from subatmospheric internal pressure conditions created by a containment overcooling event.

Containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief components within the scope of license renewal and subject to aging management review include valves (pressure boundary only), piping, tubing, fittings, and debris screens. The intended functions of containment purge, Unit 1 hydrogen purge, Unit 2 continuous containment/hydrogen purge, integrated leak rate test, service air, and containment vacuum relief components subject to an AMR include pressure boundary integrity and filtration. A complete list of containment isolation components requiring an AMR, the component's intended functions, and the applicable AMPs is provided in Table 3.2-3 of the LRA.

3.2.3.1.1 Aging Effects

In Table 3.2-3 of the LRA, the applicant identifies carbon steel, stainless steel, and brass as the materials of construction for the containment isolation system components. Loss of material was identified as an applicable aging effect for carbon steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel and brass materials are designed to be corrosion resistant in both dry and moist environments and, therefore, are not susceptible to loss of material in this environment. The air/gas environment is a compressed dry gaseous environment. Loss of material and cracking generally have not been a problem for carbon steel and brass surfaces that are exposed to air/gas environments. Based on the above, no aging effects were identified for the valves and piping/fittings (carbon steel), valves and tubing/fittings (stainless steel), Unit 1 debris screens (stainless steel), Unit 2 debris screens (carbon steel), and valves (brass) in air/gas environments. No aging effects were identified for the stainless steel tubing/fittings and Unit 1 debris screens exposed to the containment air. No aging effects were identified for the stainless steel valves and piping/fittings, tubing/fittings, and brass valves exposed to an environment of indoor not-air-conditioned or containment air.

Loss of material of carbon steel materials by corrosion may occur in moist air environments, as well as in a borated water leaks environment. The applicant identified the aging effect of loss material for the carbon steel valves, piping/fittings, and debris screen exposed to an environment of indoor not-air-conditioned or containment air or borated water leaks. In addition, loss of mechanical closure integrity was identified as an effect of aging for the carbon steel mechanical closure bolting exposed to a borated water leaks environment.

3.2.3.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment isolation system:

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the containment isolation system will be adequately managed by these AMPs for the period of extended operation.

3.2.3.2 Staff Evaluation

In Section 2.3.2.3, Section 3.2, and Table 3.2-3 of the LRA, the applicant describes its AMR of the containment isolation system for license renewal. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment isolation system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.3.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.3, Table 3.2-3, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In its review of the aging effects for carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant in order to complete its review. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment isolation system SSCs to the environments described in Section 2.3.2.3 and Table 3.2-3 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.3.2.2 Aging Management Programs

In Table 3.2-3 of the LRA, the applicant credits the following AMPs for managing the aging effects in the containment isolation system:

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Systems and Structures Monitoring Program will be used to manage loss of material for the carbon steel valves and piping/fittings exposed to an environment of indoor not-air-conditioned or containment air. The Systems and Structures Monitoring Program will also be used to manage loss of material for the carbon steel debris screen exposed to a containment air environment. The Boric Acid Wastage Surveillance Program will be used to manage loss of material for the valves, piping/fittings, and debris screen (all made of carbon steel) and loss of mechanical closure integrity for the carbon steel bolting exposed to a borated water leaks environment.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-3, the staff concludes that the AMPs identified above will effectively manage the aging effects of the containment isolation system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.3 Conclusion

The staff has reviewed the information in Section 2.3.2.3 and Table 3.2-3 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment isolation system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment isolation system as required by 10 CFR 54.21(d).

3.2.4 Safety Injection System

3.2.4.1 Technical Information in the Application

In Section 2.3.2.4 of the LRA, the applicant describes the safety injection system as being designed to provide emergency core cooling and reactivity control during and following design basis events. Portions of the safety injection system are also used for shutdown cooling functions. In addition, some portions of the safety injection system, including the shutdown cooling heat exchangers, are used in conjunction with containment spray to cool the containment.

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

3.2.4.1.1 Aging Effects

In Table 3.2-4 of the LRA, the applicant identifies stainless steel, carbon steel clad with stainless steel, carbon steel, cast iron, and brass as the materials of construction for the safety injection components. Loss of material was identified as an applicable aging effect for stainless steel, carbon steel clad with stainless steel, carbon steel, cast iron, and brass. Cracking was identified as an applicable aging effect for stainless steel and carbon steel clad with stainless steel. Fouling was identified as an applicable aging effect for stainless steel. In addition, loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building environments. No aging effects were identified for the safety injection tank, valves, piping/fittings, and tubing/fittings, orifices, and bolting, all made of stainless steel, in air/gas, indoor not-air-conditioned, or containment environments. No aging effects were identified for the stainless steel thermowells and high- and low-pressure safety injection pumps in indoor not-air-conditioned environments.

Loss of material and cracking of stainless steel materials in a treated water environment are possible aging effects under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low-flow conditions could lead to loss of material and cracking of stainless steel in treated water. The applicant identified the aging effect of loss of material for the stainless steel high-pressure safety injection (HPSI) pumps exposed to treated water-borated environments. Loss of material and cracking were identified as aging effects for the stainless steel safety injection tanks, low-pressure safety injection (LPSI) pumps, shutdown cooling heat exchanger channel nozzles, channel facings, channel cover facings, valves, piping/fittings, thermowells, and tubing/fittings, and orifices exposed to the treated water-borated environment.

For stainless steel heat exchanger tubes or pump cooler tubes exposed to treated water environments, the tubes may be susceptible to fouling which, if unattended, has the potential to block the flow of coolant through the tubes and in some cases to produce corrosive environments that could lead to a loss of tube material. The applicant identified the aging effects of loss of material and fouling for the stainless steel shutdown cooling heat exchanger tubes, Unit 1 LPSI pump cooler tubes, and HPSI pump cooler tubes exposed to a treated water-borated or treated water-other environment. Based on the same reasoning, the applicant identified loss of material, fouling, and cracking for the shutdown cooling heat exchanger tubes and Unit 1 LPSI pump cooler tubes exposed to treated water-borated environments. The applicant also identified the aging effects of loss of material and cracking for the shutdown cooling heat exchanger tube sheets, which are made of carbon steel clad with stainless steel, exposed to treated water-borated environments. Similarly, the applicant identified loss of material for the same shutdown cooling heat exchanger tube sheets exposed to treated water–other environments.

Loss of material of carbon steel and cast iron materials through general corrosion may occur when in contact with treated water environments. The applicant identified the aging effect of loss of material for the carbon steel shutdown cooling heat exchanger shells, baffles, and tube supports, Unit 2 carbon steel HPSI pump cooler shells, and Unit 1 cast iron LPSI and HPSI pump cooler shells, all exposed to treated water-other environments. Similarly, the applicant identified the aging effect of loss of material for the Unit 1 brass HPSI pump cooler tube shields. Loss of material of carbon steel and cast iron materials by corrosion may occur in moist air environments (e.g., ventilated, sheltered, or reactor building). The applicant identified the aging effect of loss of material for the carbon steel shutdown cooling heat exchanger shells, shutdown cooling heat exchanger channel heads and channel covers, Unit 2 HPSI pump cooler shells, and Unit 1 cast iron HPSI and LPSI pumps cooler shells, exposed to an indoor not-air-conditioned or borated water leaks environment. In addition, loss of mechanical closure integrity was identified with the carbon steel mechanical closure bolting exposed to a borated water leaks environment.

3.2.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the safety injection system:

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the safety injection system will be adequately managed by these AMPs for the period of extended operation.

3.2.4.2 Staff Evaluation

In Section 2.3.2.4, Section 3.2, and Table 3.2-4 of the LRA, the applicant describes its AMR of the safety injection system for license renewal. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the safety injection system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.4.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.4, Table 3.2-4, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant in order to complete its review. The staff’s evaluation of the bolting, including its review of the applicant’s response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s response to the above RAI, the staff finds that the aging effects that result from contact of the safety injection system SSCs with the environments described in Section 2.3.2.4 and Table 3.2-4 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.4.2.2 Aging Management Programs

In Table 3.2-4 of the LRA, the applicant credits the following AMPs for managing the aging effects in the safety injection system:

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program will be used to manage loss of material, cracking, or fouling for all the stainless steel components exposed to a treated water-borated or treated water-other environment. The Chemistry Control Program and Galvanic Corrosion Susceptibility Inspection Program will be used to manage loss of material for the components made of carbon steel, cast iron, and brass exposed to a treated water-other environment. The Systems and Structures Monitoring Program will be used to manage loss of material for the carbon steel and cast iron components exposed to an indoor-not-air-conditioned-environment. The Boric Acid Wastage Surveillance Program will be used to manage loss of material for the carbon steel and cast iron components exposed to a borated water leaks environment. Finally, the Boric Acid Wastage Surveillance Program will be used to manage loss of mechanical closure integrity for the carbon steel bolting exposed to a borated water leaks environment.

The above AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-4, the staff concludes that the AMPs identified above will effectively manage the aging effects of the safety injection system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.3 Conclusion

The staff has reviewed the information in Section 2.3.2.4 and Table 3.2-4 of the LRA, and the additional information included in the applicant's response to the above RAI. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the safety injection system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the safety injection system as required by 10 CFR 54.21(d).

3.2.5 Containment Post-Accident Monitoring

3.2.5.1 Technical Information in the Application

In Section 2.3.2.5 of the LRA, the applicant states that the containment post-accident monitoring system includes the following subsystems:

- containment hydrogen monitoring
- post-accident sampling (Unit 2 only)
- containment atmosphere radiation monitoring

Containment hydrogen monitoring indicates the hydrogen gas concentration in the containment atmosphere following a loss-of-coolant accident. Its mechanical portions provide a flow path from the containment to the hydrogen analyzers and then back to the containment. 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. Containment atmosphere radiation monitoring measures radioactivity in the containment air. The mechanical portions of containment atmosphere radiation monitoring provide a flow path from the containment to the monitors and then back to the containment.

Containment post-accident monitoring components subject to an aging management review include valves (pressure boundary only), sample vessel, flexible hoses, piping, tubing, and fittings. The intended function of containment post-accident monitoring components subject to an AMR is pressure boundary integrity. A complete list of the containment post-accident monitoring components requiring an AMR, the components intended functions, and the applicable AMPs is provided in Table 3.2-5 of the LRA.

3.2.5.1.1 Aging Effects

In Table 3.2-5 of the LRA, the applicant identifies stainless steel and carbon steel as the materials of construction for the containment post-accident monitoring components. Loss of mechanical closure integrity was identified as an applicable aging effect for carbon steel mechanical closure bolting exposed to a borated water leaks environment.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry and moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building environments. No aging effects were identified for the stainless steel flex hoses, valves, sample vessels (Unit 1), or tubing/fittings in an air/gas, containment air, or indoor-not-air-conditioned environment.

Loss of material of carbon steel materials may occur in a borated water environment or in the event of borated water leaks from other plant systems. Loss of mechanical closure integrity was identified with carbon steel mechanical closure bolting exposed to borated water leaks.

3.2.5.1.2 Aging Management Programs

The Boric Acid Wastage Surveillance Program is utilized to manage aging effects in the containment post-accident monitoring system. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the containment post-accident monitoring system will be adequately managed by this AMP for the period of extended operation.

3.2.5.2 Staff Evaluation

In Section 2.3.2.5, Section 3.2, and Table 3.2-5 of the LRA, the applicant describes its AMR of the containment post-accident monitoring system for license renewal. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment post-accident monitoring system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2.1 Aging Effects

The staff reviewed the information in Section 2.3.2.5, Table 3.2-5, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In its review of the aging effects of carbon steel bolting (mechanical closure), the staff found that additional information was required from the applicant in order to complete its review. The staff's evaluation of the bolting, including its review of the applicant's response to the RAI, is provided in Section 3.2.1.2.1 of this SER.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the containment post-accident monitoring system SSCs with the environments described in Section 2.3.2.5 and Table 3.2-5 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.5.2.2 Aging Management Programs

In Table 3.2-5 of the LRA, the applicant credits Boric Acid Wastage Surveillance Program for managing the aging effects in the containment post-accident monitoring system.

The Boric Acid Wastage Surveillance Program will be used to manage loss of mechanical closure integrity for the carbon steel bolting exposed to a borated water leaks environment. This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.2-5, the staff concludes that the AMP identified above will effectively manage the aging effects of the containment post-accident monitoring system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.3 Conclusion

The staff has reviewed the information in Section 2.3.2.5 and Table 3.2-5 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment post-accident monitoring system will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.4-1, the staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the containment post-accident monitoring system as required by 10 CFR 54.21(d).

3.3 Auxiliary Systems

In Section 3.3, "Auxiliary Systems," of the LRA the applicant describes the (AMR) for the auxiliary systems. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the auxiliary systems. The staff reviewed Section 3.3 and the applicable portions of Appendices A, B, and C to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3) for the auxiliary system structures and components that are determined to be within the scope of license renewal and subject to an AMR.

The St. Lucie auxiliary systems include the following 16 systems:

(1) Chemical and Volume Control
(2) Component Cooling Water
(3) Demineralized Makeup Water (Unit 2 only)
(4) Diesel Generators and Support Systems
(5) Emergency Cooling Canal
(6) Fire Protection
(7) Fuel Pool Cooling
(8) Instrument Air
(9) Intake Cooling Water
(10) Miscellaneous Bulk Gas Supply
(11) Primary Makeup Water
(12) Sampling
(13) Service Water
(14) Turbine Cooling Water (Unit 1 only)
(15) Ventilation
(16) Waste Management

In Subsection 2.3.3 of the LRA, the applicant provides a description of these systems and identifies the components requiring aging management reviews. The staff's evaluations of the scoping methodology and the auxiliary systems' structures and components included within the scope of license renewal and subject to an AMR are documented in Sections 2.1 and 2.3.3, respectively, of this SER. In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). In Appendix B of the LRA, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In Appendix C of the LRA, the applicant describes the processes used to identify many of the applicable aging effects for the structures and components that are subject to an AMR. In Appendix D of the LRA, the applicant states that no changes to the St. Lucie TS have been identified. A review of each of the auxiliary systems follows.

3.3.0 Aging Management Programs

3.3.0.1 Chemistry Control Program Fuel Oil Chemistry Subprogram

The applicant describes its fuel oil chemistry subprogram in Section B.3.2.5.3 of the LRA. This section addresses the procedures for controlling the fuel oil chemistry in order to ensure its compatibility with the materials of construction of the components exposed to the fuel oil environment. The staff reviewed Section B.3.2.5.3 of the LRA to determine whether the applicant has demonstrated that the fuel oil chemistry subprogram will adequately manage the applicable aging effects for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.0.1.1 Technical Information in the Application

In Section 3.2.5.3 of Appendix B of the LRA, the applicant states that the fuel oil chemistry subprogram is a plant-specific program and was developed in accordance with the guidance of ASTM D975-81. The program has been an ongoing program at St. Lucie since the initial start up and has evolved over many years of plant operation. The applicant states that the Aging Management Program XI.M30, “Fuel Oil Chemistry,” in the GALL report contains additional aspects such as water removal and internal tank inspection. The applicant also states that aging effects will be managed by the fuel oil chemistry subprogram to ensure that significant degradation is not occurring and the component intended functions will be maintained for the period of extended operation.

The applicant provides the methods for controlling fuel oil quality in order to ensure that it is compatible with the materials of construction of the components exposed to fuel oil. Use of contaminated fuel oil could lead either to corrosion damage of storage tanks or to accumulation of particulate or biological growth that would interfere with the operation of safety-related equipment. In the fuel oil chemistry subprogram, the applicant specified fuel oil analyses, minimum sampling frequencies, and acceptance criteria needed for maintaining the required fuel oil quality. The acceptance criteria for these tests are based, to a great extent, on the ASTM standards listed in the LRA. Also, the applicant identified corrective actions which would be taken if the fuel oil did not meet the prescribed specifications.

3.3.0.1.2 Staff Evaluation

The staff’s evaluation of the fuel oil Chemistry Control Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff’s evaluation of these program attributes is provided separately in Section 3.0.5.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The scope of the fuel oil chemistry subprogram is focused on managing the conditions that may cause loss of material of diesel fuel oil system component internal surfaces. The subprogram serves to reduce the potential of exposure of the internal surfaces to fuel oil contaminated with water and microbiological organisms. The staff found the program scope acceptable because the aging effects specified can be managed by the program discussed in the LRA.

Preventive Actions: Maintaining proper fuel oil chemistry through regular inspections for the presence of water, particulate, and other contaminants and taking appropriate corrective actions will prevent the degradation of the components in the systems containing fuel oil. Periodic cleaning of the diesel fuel oil storage tanks and periodic draining of water collected at the bottom of the tanks minimizes the amount of water and the length of contact time.

In this attribute, the applicant stated that tank inspection and water removal are performed as part of the periodic surveillance and preventive maintenance program. Corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom. Ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring. By letter dated July 18, 2002, the staff requested, in RAI B.3.2.5-3, the applicant to provide additional information concerning the identification of the locations in the fuel oil components (e.g., fuel oil tank bottoms) at which periodic fuel oil samples are obtained. The staff further requested the applicant to indicate when thickness measurements are used to detect aging effects on the tank bottom.

In its response dated September 26, 2002, the applicant stated that degradation of the tank bottoms due to accumulation of contaminants has not been experienced at St. Lucie. In order to ensure that contaminants are not accumulating and causing degradation of the diesel fuel oil components, the diesel fuel oil quality is managed by the Chemistry Control Program – Fuel Oil Chemistry Subprogram. This program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces and the emergency diesel generator (EDG) fuel supply system.

To ensure purity of the fuel throughout the system, upon receipt of new fuel oil and prior to transferring the oil from the tanker to the storage tanks, fuel is tested to specific ASTM standards, verifying proper American Petroleum Institute (API) gravity, kinematic viscosity, flash point, appearance and color. In addition, fuel in the storage tanks are sampled and tested at least once every 31 days in accordance with ASTM D2276-83 and by verifying total particulate contamination of less than 10 mg/liter. Prior to obtaining storage tank samples, the tanks are placed on recirculation to ensure that the samples are representative of the bulk fuel oil in the tanks.

Accumulated water is also removed from both of the storage tanks as required by the St. Lucie Technical Specifications. Accumulated water from the bottom of the tanks is removed at least once per 92 days. In addition to the removal of water accumulation per St. Lucie Technical Specification requirements, the storage tanks are drained, cleaned of accumulated sediment, and visually inspected for internal corrosion every 10 years. If no contaminants are found for the inspections, loss of material would be unlikely and thus thickness measurement of the tank bottoms will not be necessary. To date, all of the tanks have been inspected with no indication of aging mechanisms or effects. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

On the basis of its review, the staff finds the response of the applicant reasonable and adequate because the procedures undertaken by the applicant ensure the purity of the fuel throughout the system and remove accumulated water from both the storage tanks as required by the St. Lucie Technical Specifications. In addition, the staff finds that these procedures are adequate because they include all the activities needed for maintaining the quality of fuel oil and managing the potential aging effects of the components in the systems containing fuel oil.

Parameters Monitored or Inspected: The fuel oil chemistry subprogram monitors fuel oil quality by performing a number of tests. Most of these tests follow the procedures specified in the ASTM standards. For determining water and sediment content and for particulate testing in fuel oil, the applicant will follow the procedures described in ASTM D-1796 and ASTM D-2276, respectively. The staff finds that the procedures used by the applicant for monitoring fuel oil quality with regard to its effect on the components exposed to the fuel oil environment are based on well-established methods and the applicant's inspection program is, therefore, acceptable.

Detection of Aging Effects: The fuel oil chemistry subprogram is an activity which minimizes aging effects by controlling the fuel oil environment and taking appropriate corrective actions. It does not directly detect aging effects. The purpose of the program is to ensure that optimum environment in the systems containing fuel oil exists and that no component degradation due to aging effects is occurring. The staff found this acceptable because the chemistry program is a preventative program and as such is not credited for detecting aging effects.

Monitoring and Trending: In the LRA the applicant states that water and particulate contaminants are monitored and trended. The site Technical Specifications require that sampling and analysis of fuel oil chemistry are performed monthly. The sampling and analysis will provide an opportunity to detect fuel oil conditions that can lead to fuel oil tank degradation so that appropriate corrective actions could be taken in a timely manner. In addition, the freshly delivered oil will be sampled for water and sediment content prior to its transfer to the supply tanks. The staff reviewed the applicant's monitoring and trending program and found that it will provide the applicant with an effective way for controlling fuel oil quality.

Acceptance Criteria: In the LRA, the applicant states that the acceptance criteria specified in ASTM D2276 for the chemistry parameters required to be monitored and controlled are listed in the St. Lucie Technical Specifications and procedures controlled by the Chemistry Control Program. Adherence to the criteria will ensure that the quality of fuel oil will be kept at an acceptable level and any departure from it will result in timely corrective action. The staff found the acceptance criteria for the fuel oil chemistry subprogram to be effective in controlling aging effects for the components and systems exposed to fuel oil because the criteria allows for early detection and corrective action of fuel oil chemistry deviations.

Operating Experience: In the LRA, the applicant states that operating experience at St. Lucie Units 1 and 2 has included particulate contamination attributable to a contaminated tanker truck transfer pump and hose. The applicant further stated that no instances of fuel oil system component failures attributable to contamination have been identified. By letter dated July 18, 2002, the staff requested the applicant to provide additional information (RAI 3.2.5-4) concerning the corrective action taken to prevent recurrence, and to discuss the operating experience regarding the effectiveness of the aging management program such that aging degradation, which could lead to the loss of an intended function, will be identified and addressed before it results in age-related failures of the fuel oil system components.

In its response to the NRC dated September 26, 2002, the applicant stated that particulate contamination of the diesel fuel oil storage tanks (DOSTs) was discovered when an off-site contract laboratory identified out of specification particulate contamination in three of the four DOSTs. This event was caused by the use of a contaminated fuel oil tanker truck transfer pump and hose. To prevent recurrence of contamination caused by the contaminated tanker truck transfer pump and hose, the following corrective actions were taken: (1) the chemistry procedure was revised to require flushing the first 100 gallons of diesel fuel oil into drums to ensure cleanliness of the tanker, pump, and discharge hose; (2) a permanent filtration unit was installed at the site which is connected to the fuel oil tanker discharge hose to remove possible contamination after the initial 100-gallon flush; (3) chemistry procedures were revised to correct deficiencies (e.g., use of incorrect solvent in the sampling process). In addition, St. Lucie diesel fuel oil analytical techniques were reviewed by an outside vendor to ensure compliance with ASTM standards.

The applicant also stated that to ensure that degradation of the diesel fuel oil tank and fuel supply system does not occur, exposure of the internal surfaces to contaminants in the fuel oil is minimized. This is accomplished by implementing the following aging management programs for the diesel generator fuel oil system.

- The Chemistry Control Program – fuel oil chemistry subprogram provides for monitoring of fuel oil parameters in accordance with ASTM Standards (as specified in the St. Lucie Technical Specifications), addition of biocides to minimize biological activity, addition of stabilizers to prevent biological breakdown of the diesel fuel, and addition of corrosion inhibitors to mitigate corrosion.

- The periodic surveillance and preventive maintenance program (LRA Appendix B Subsection 3.2.11 page B-46) provides for the periodic removal of water from the fuel oil storage tanks and the draining and cleaning of the storage tanks every 10 years.

Furthermore, the applicant stated that based on a review of St. Lucie plant-specific operating experience, with the exception of the particulate contamination described above, no instances of fuel oil component failures attributed to contamination have been identified. Visual inspection of the storage tanks has not identified any degradation due to corrosion or any other mechanism.

On the basis of its review, the staff finds the response of the applicant reasonable and adequate because both the corrective action undertaken by the applicant to prevent recurrence and the result of the review of plant-specific operating experience demonstrate the effectiveness of the aging management program such that aging degradation will be identified and addressed before it results in age-related failures of the fuel oil system.

Operating experience with the systems covered by the fuel oil chemistry subprogram has demonstrated the effectiveness of the program. The program has been an ongoing program at St. Lucie since the initial start up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations. The review of operating experience at St. Lucie showed that there had been no instances of fuel oil system component failures attributed to contamination. The tank inspection was performed in accordance with station technical specifications. As a result of operating experience, the staff agrees that the applicant implemented an effective fuel oil chemistry subprogram, and the program will effectively manage the applicable aging effects for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.0.1.3 FSAR Supplement

Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the chemistry control programs at St. Lucie. The program descriptions are consistent with the material contained in Section 3.2.5.3 of Appendix B and are therefore acceptable to the staff.

3.3.0.1.4 Conclusion

The staff has reviewed the information provided in Section 3.2.5.3 of Appendix B of the LRA, the applicant's responses to the staff's RAIs, and the summary description of the Chemistry Control Program in Section 18.2.5 of Appendix A1 and Section 18.2.4 of Appendix A2 of the FSAR supplement. On the basis of this review and the above evaluation, with the exception of open item 3.0.2.2-1, the staff finds that the applicant has demonstrated that the effects of aging associated with the structures and components of the fuel oil chemistry subprogram will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory item 3.0.2.2-1, the staff concludes that the FSAR supplement contains an appropriate summary description of the programs and activities for managing the effects of aging for the fuel oil systems as required by 10 CFR 54.21(d).

3.3.0.2 Intake Cooling Water System Inspection Program

The Intake Cooling Water System Inspection Program is described in Section 3.2.10 of Appendix B to the LRA. The applicant credited this program for managing the aging of components in the intake cooling water system and the component cooling water system. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Intake Cooling Water System Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.0.2.1 Technical Information in the Application

The Intake Cooling Water Inspection Program is credited for aging management of specific component/commodity groups in the intake cooling water system and the component cooling water system. This program is plant specific, although certain aspects of the Intake Cooling Water Inspection Program are comparable to GALL Program XI.M20, "Open-Cycle Cooling Water System." The applicant 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 systems at St. Lucie Units 1 and 2.

The aging effects requiring management in the intake cooling water system are loss of material for carbon steel, stainless steel, cast iron, aluminum brass, aluminum bronze, bronze, and Monel components and cracking for rubber and fiberglass components. The aging effects requiring management in the component cooling water system are loss of carbon steel, stainless steel, cast iron, and aluminum bronze components and loss of material and fouling for aluminum brass components. The aging effect requiring management for carbon steel mechanical bolting is loss of mechanical closure integrity.

The Intake Cooling Water System Inspection Program addresses the aging effects of loss of material due to various corrosion mechanisms and biological and particulate fouling. It also addresses internal inspection of the intake cooling water piping to identify and manage loss of material on the external surface of buried piping. The program utilizes differential pressure performance evaluations, systematic inspections, and corrective actions to ensure that loss of material or fouling does not lead to loss of intended functions of license renewal components. NRC Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” requires the implementation of an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage caused by biological fouling, particulate fouling, corrosion, protective coating failures, and silting problems in systems and components supplied with intake cooling water. The Intake Cooling Water System Inspection Program scope, method, and testing frequencies are in accordance with the commitments under GL 89-13.

3.3.0.2.2 Staff Evaluation

The staff evaluated the program against 10 program attributes that are described in Appendix A to NUREG 1800 as program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff’s evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The LRA states that the Intake Cooling Water Inspection Program is credited for aging management of specific components/commodity groups in the intake cooling water system and the component cooling water system. Section 3 of the LRA indicates that the program is credited for strainers, valves, piping, fittings, and orifices in the intake cooling water system and heat exchanger components in the component cooling water system. The program addresses the aging effects of loss of material due to various corrosion mechanisms and biological and particulate fouling. It also addresses internal inspection of the intake cooling water piping to identify and manage loss of material on the external surface of buried piping. The staff finds the program scope is acceptable because it includes the components and aging effects that credit the program.

Preventive Actions: The LRA states that the Intake Cooling Water Systems Inspection Program is preventive in nature since it provides for the periodic inspection and maintenance of internal linings and coatings of piping and components exposed to aggressive cooling water environments. The program employs performance monitoring, testing, and periodic inspection and cleaning of heat exchangers, nondestructive examination of heat exchanger tubes, and backflushing and inspection of the intake cooling water strainers. While external coatings are applied to portions of the intake cooling water system to minimize corrosion, coatings are not credited in the determination of aging effects requiring management.

The UFSAR for St. Lucie Unit 1 states that the component cooling water heat exchanger components exposed to raw water are protected by sacrificial anodes located in the heat exchangers. The applicant did not provide any information about inspection or replacement of these anodes. Therefore, the staff issued RAI B.3.2.10-4 requesting information about whether these sacrificial anodes are credited in preventing or mitigating loss of material due to corrosion of the heat exchanger components exposed to raw water. The staff also asked the applicant to identify and describe the program that provides for inspection of these anodes. By letter dated September 26, 2002, the applicant stated that each of the Unit 1 CCW heat exchangers has sacrificial anodes installed as a preventive measure to minimize the potential for corrosion of parts exposed to raw water; however, the anodes are not credited with reducing the loss of material. The staff had also issued RAI 3.3.2-3, asking whether the CCW head exchanger tubes were subject to cracking, as had been found in similar heat exchanger tubes and conditions at Turkey Point Units 3 and 4. In its September 26, 2002, response to RAI 3.3.2-3, the applicant stated that the St. Lucie CCW heat exchanger tubes were not subject to cracking because, unlike to Turkey Point, St. Lucie had not performed a chemical injection and St. Lucie had sacrificial anodes. From these two responses, it was not clear to the staff whether the applicant had credited the sacrificial anodes for preventing cracking of the tubes and, if so, whether the applicant had a sufficient program in place to inspect and replace the anodes. By letter dated November 27, 2002, the applicant clarified that the anodes are not credited for the prevention of cracking in the CCW heat exchanger tubes. Therefore, the staff finds it acceptable that the anodes are not covered by this program.

Based on the above, the staff finds the applicant’s preventive actions adequate and acceptable, because the performance monitoring, testing, and periodic cleaning of heat exchangers and the backflushing of the system will mitigate the aging effects. The staff also notes the preventative measures of coatings and sacrificial anodes, although these are not credited for license renewal.

Parameters Monitored or Inspected: The LRA states that surface conditions of piping/components and their internal linings are visually inspected for degradation. Wall thickness measurements are taken when deemed necessary. Pressures, temperatures, and flows associated with the CCW heat exchangers are monitored during normal operation to verify heat transfer capability. Tube integrity of CCW heat exchangers is monitored by periodic nondestructive examinations to ensure early detection of aging effects. The staff finds the proposed measures reasonable and acceptable, because visual inspections, wall thickness measurements, and monitoring of pressures, temperatures, and flow will permit timely detection of the aging effects.

Detection of Aging Effects: The LRA states that visual inspections of piping/components are performed to identify loss of material, fouling, damaged linings, and degraded material condition. Volumetric testing may be utilized to measure internal and external surface conditions and the extent of wall thinning based on the evaluation of the examination results. Monitoring of the CCW heat exchangers is conducted to provide early identification of fouling and degraded conditions that could impact the ability of the CCW heat exchangers to perform their intended function. Periodic tube inspections and cleaning are performed to assure heat exchanger performance and integrity. The staff finds the applicant’s techniques for the detection of aging effects adequate and acceptable, because the proposed visual inspections and volumetric testing methods are consistent with industry practice and experience.

Monitoring and Trending: The LRA states that the inspection scope, method, and testing frequencies are in accordance with the applicant's commitments under 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. CCW heat exchanger tube condition is determined by eddy current testing and is documented accordingly. Heat exchanger tube cleaning, tube replacement, or other corrective actions are implemented as required.

In RAI B.3.2.10-1, the staff asked the applicant to provide the inspection frequencies, bases, and the most recent operating history supporting the adequacy of this program for components in the intake cooling water system in stainless steel, carbon steel, and cast iron intake cooling water pumps; rubber intake cooling water pump expansion joints; and aluminum-bronze pump discharge valves exposed externally to the raw water environment. The LRA had provided this information for other components in the intake cooling water system. By letter dated September 26, 2002, the applicant provided the following response:

> As indicated on LRA Table 3.3-9 (pages 3.3-59 and 3.3-62), St. Lucie has no cast iron or carbon steel intake cooling water (ICW) pumps. The pump casings are made of stainless steel or aluminum bronze. The current frequency of inspection for the ICW pumps is 96 months. This frequency is appropriate based on the operating and maintenance history of these components at St. Lucie. The current frequency of replacement of the Unit 1 ICW pump expansion joints is 120 months. This frequency was also determined to be acceptable based upon past experience. The frequency of these inspections may be adjusted as necessary based on future plant-specific performance and/or industry experience. The Unit 2 ICW pump expansion joints are constructed of stainless steel.
>
> Other than vent, drain, and instrument valves, there are no aluminum bronze valves in ICW, and none are exposed externally to a raw water environment.

The staff finds the applicant's response acceptable and the issues related to RAI B.3.2.10-1 resolved, because none of the vulnerable components are exposed to a raw water environment.

In RAI B.3.2.10-3, the staff asked the applicant to identify the plant procedures and applicable documents that contain detailed guidance related to performance monitoring testing and tube examinations of heat exchangers. By letter dated September 26, 2002, the applicant provided the names of the procedures and stated that the procedures contain CCW heat exchanger performance monitoring acceptance criteria that ensure that design basis and technical specification requirements for heat transfer capability are maintained. The applicant also stated that guidelines are provided for cleaning, inspecting, and testing the heat exchangers. The staff finds that monitoring to ensure that design basis and technical specification requirements for heat transfer capability are maintained is acceptable.

In RAI B.3.2.10-5, the staff asked the applicant to identify the criteria used to determine which components should be inspected. By letter dated September 26, 2002, the applicant stated that the internal inspections of intake cooling water piping and components are normally performed during the refueling outages on a scope and frequency based on past inspection results. The current inspection covers 100 percent of the internally accessible components (including linings of fittings such as elbows) and is performed on an every other refueling interval. Based on St. Lucie plant-specific operating experience, this inspection scope and frequency are adequate to ensure that ICW piping will continue to perform its intended function for the period of extended operation. The applicant stated that the frequency of the inspections may be adjusted as necessary based on inspection results and industry experience. The staff finds that adjusting the scope and frequency based on operating experience is acceptable, and the current scope of inspections appears reasonable.

The staff finds that the proposed methodologies will provide effective monitoring and trending of aging effects and are therefore acceptable.

Acceptance Criteria: The LRA stated that visual examinations of the internal surface of piping, fittings, heat exchangers, and basket strainers are performed to identify loss of material. When required, determination of wall thickness values is performed and evaluated. The LRA also states that monitoring heat exchanger differential pressure, flow, and temperatures during normal operation ensures that the design basis heat transfer capability is maintained. Periodic backflushing removes the accumulation of biofouling agents, corrosion products, and silt. Biological and particulate materials not removed by backflushing are removed when the system is opened for cleaning and inspection.

As described above, performance monitoring acceptance criteria for the CCW heat exchanger ensure that design basis and technical specification requirements for heat transfer capability are maintained. Also, wall thickness values are determined and wall thickness is evaluated, as required. The staff finds that using acceptance criteria that ensure that the design basis and technical specification requirements are maintained is acceptable.

Operating Experience: The LRA states the following:

> The existing Intake Cooling Water System Inspection Program has been an ongoing formalized inspection program at St. Lucie since 1990. The program was formally implemented as a result of Generic Letter 89-13, which documented the need to implement monitoring of service water systems to ensure that they would perform their safety-related function. The conservative philosophy established within the program has been successful in managing the loss of material due to corrosion and fouling of the Component Cooling Water heat exchangers. Various sections of the Intake Cooling Water piping, basket strainers, and heat exchangers are periodically examined using visual examination to determine the effects of corrosion and fouling. Results are evaluated and components are either repaired or replaced as required. Branch connections are examined as plant/industry experience warrants.
>
> Metallurgical analyses of Component Cooling Water heat exchanger tubes, performed in 1988 and 1991, indicated that erosion of aluminum brass tubes was caused by shells lodged in the tubes. Localized erosion caused small pinhole leaks in the tubes. To preclude erosion from occurring, the Component Cooling Water heat exchangers are opened periodically for cleaning and inspection.
>
> A review of operating history for Intake Cooling Water and Component Cooling Water shows that the current aging management programs have supported system availability above its performance criteria for the period from May 1996 through June 2001. In addition, there have been no functional failures attributed to aging of pressure-retaining components during that period.

On page B-45 of Appendix B to the LRA, the applicant states that the Intake Cooling Water System Inspection Program includes examination of the ICW branch connections as warranted by plant and industry experience. Since this is an existing program, the staff issued RAI 3.3.2-5 requesting that the applicant describe the findings of past examinations and discuss which aging effect(s), if any, have been observed at the branch connections. The applicant was also asked to include the root cause of any identified aging effects. In its response dated

September 26, 2002, the applicant stated that the past inspections of ICW piping have identified susceptibility to loss of material due to corrosion resulting from localized internal and external coating failures on branch lines. The applicant added that small branch lines may not have an internal lining/coating based upon size, and some consist of stainless steel instrumentation tubing. The applicant further stated that accessible portions of branch connections, which typically constitute vents, drains, and instrumentation lines, are examined internally during the main header crawl-through inspections, and all small-bore lines are inspected externally. The applicant provided several examples of the findings of past inspections of branch connections. The examples included loss of material due to corrosion, leading to through-wall leaks in some cases. The staff finds the RAI response acceptable because the applicant described the findings of past examinations along with root causes as requested.

The staff discussed the operating history at length with the applicant during public meetings. The staff finds that the operating experience supports the applicant's conclusion that the Intake Cooling Water System Inspection Program provides reasonable assurance that the aging of systems and components within the scope of the program will be adequately managed.

3.3.0.2.3 FSAR Supplement

The staff has reviewed the summary description of the Intake Cooling Water System Inspection Program in the FSAR supplement in Appendix A to the LRA. With the exception of confirmatory item 3.0.2.2-1, the staff that the FSAR supplements contain the essential elements of the program and, therefore, provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

3.3.0.2.4 Conclusion

The staff has reviewed the information provided in Section 3.2.10 of Appendix B of the LRA; the applicant's September 26, 2002, response to the staff's RAIs; the applicant's November 27, 2002, letter providing supplements to its September 26, 2002, letter; and the summary description of the Intake Cooling Water System Inspection Program in Appendix A of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.2.2-1, the staff finds, that the Intake Cooling Water System Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Chemical and Volume Control

3.3.1.1 Summary of Technical Information in the Application

The chemical and volume control system (CVCS) provides a continuous feed and bleed for the reactor coolant system to maintain proper water level and to adjust boron concentration. At St. Lucie, CVCS consists of a charging subsystem, a letdown subsystem, and a boric acid makeup subsystem. Details of the CVCS are described in Section 9.3.4 of the UFSAR's for Units 1 and 2.

3.3.1.1.1 Aging Effects

Components of the CVCS are described in Section 2.3.3.1 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), housings, tanks, heat exchangers, strainers, orifices, thermowells, piping, tubing and fittings, and bolting. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of treated water (borated and other). Exposure of stainless steel to outdoor, air-gas, indoor-not-air-conditioned, and containment air has no aging effects. One exception is that previously heat-traced stainless steel piping and fittings components exposed to an indoor-not-air conditioned environment are identified as being subject to cracking. Another exception is that stainless steel components located in the ECCS pipe tunnel (outdoor environment) are identified as being subject to SCC and loss of material. Carbon steel bolting is identified as being subject to loss of mechanical closure integrity from the borated water leak environment and as having no aging effect from exposure to outdoor, indoor-not-air-conditioned, and containment air environments. For St. Lucie Units 1 and 2, fatigue of regenerative heat exchangers, letdown heat exchangers, valves, piping, and fittings is identified as a TLAA and is addressed in Section 4.3.2 of the LRA.

3.3.1.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the CVCS:

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the CVCS will be adequately managed by these AMPs for the period of extended operation.

3.3.1.2 Staff Evaluation

The applicant described its AMR of the CVCS for license renewal in Section 2.3.3.1 and Section 3.3, Table 3.3-1, pages 3.3-13 through 3.3-17. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the CVCS will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.1, Table 3.3-1, pages 3.3-13 through 3.3-17, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In Table 3.3-1 of the LRA, the applicant identified the air/gas environment as an applicable internal environment for the stainless steel boric acid makeup tanks, volume control tanks, valves, piping/ fittings, and tubing/fittings. The applicant did not identify any aging effects of these components in the air/gas environment. The aging effects associated with exposure to the air/gas environment are identified in Table 3.3-1 and are discussed in Section 5 of Appendix C to the LRA. In Appendix C, Section 4.1.3, "Air/Gas," of the LRA, the applicant describes the air/gas environments found at St. Lucie Units 1 and 2. Aging effects of components exposed to the air/gas environment depend, in part, on the type of air/gas environment, the operating temperature, and the water content. By letter dated July 1, 2002, the staff requested in RAI 3.3.1-1 that the applicant provide additional information on the characteristic parameters of the air/gas environments applicable to the CVCS components and also provide the basis by which the applicant determined that there are no aging effects requiring management for those components that are exposed to the air/gas environment.

In its response dated September 26, 2002, the applicant stated that Table 3.3-1 (pages 3.3-13 and 3.3-14) of the LRA indicates which CVCS components are exposed to internal air/gas environments. These CVCS components are the volume control tanks, the boric acid makeup tanks, and the associated valves, piping/fittings, and tubing/fittings which are located above the water level in these tanks. The type of air/gas environment and the bases for the determination of no aging effects requiring management for these components are provided below:

- The volume control tanks, internal gas space surfaces and associated valves, piping/fittings, and tubing/fittings are exposed to a non-wetted hydrogen environment with traces of nitrogen, oxygen, and helium at a temperature less than 150 ^{o}F. The construction material of these components is stainless steel. Per Appendix C, Sections 5.1 and 5.2 (pages C-11 and C-14, respectively) of the LRA, this material is not susceptible to loss of material or stress corrosion cracking in this environment. A review of St. Lucie plant-specific operating experience validated that there are no aging effects requiring management for these components.

- The boric acid makeup tanks, internal gas space surfaces and associated valves, piping/fittings, and tubing/fittings are exposed to an air/gas environment of indoor-not-air-conditioned air at a maximum temperature of 104 ^{o}F. The construction material of these components is stainless steel. Per Appendix C, Sections 5.1 and 5.2 (pages C-11 and C-14 respectively), of the LRA, this material is not susceptible to loss of material or stress corrosion cracking in this environment. A review of St. Lucie plant-specific operating experience validated that there are no aging effects requiring management for these components.

Therefore, the applicant concluded that no aging effects requiring management have been identified for these components.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.1-1 clarifies and satisfactorily resolves this item because it provided the characteristic parameters of the air/gas environments applicable to these CVCS components, demonstrated that there are no aging effects requiring management for these components, and described the plant-specific operating experience which validates the conclusion.

Components of the CVCS that are exposed externally to an outdoor environment and an outdoor environment (ECCS pipe tunnel) are stainless steel piping/fitting (refueling water tanks to charging pump suctions) and bolting (mechanical closures, both carbon steel and stainless steel). The outdoor environment is characterized by moist, salt-laden air, temperature of 27 ^{o}F 93 ^{o}F, 73 percent average humidity, and exposure to weather, including precipitation and wind. The applicant identified loss of materials and cracking as the applicable aging effects for CVCS components that are exposed externally to an outdoor environment and identified SCC and loss of material for stainless steel components located in the ECCS pipe tunnel. By letter dated July 1, 2002, the staff requested, in RAI 3.3.1-2, that the applicant explain the difference between the outdoor environments described in Appendix C, Section 4.2.1, of the LRA, and the outdoor environment in the ECCS pipe tunnel and also explain how this difference leads to differences in aging effects.

In its response dated September 26, 2002, the applicant stated that as discussed in Appendix C, Section 5.2 (page C-14) of the LRA, sensitized stainless steels exposed to atmospheric conditions with high levels of contaminants (e.g., saltwater) are considered potentially susceptible to SCC. Additionally, as discussed in LRA Appendix C, Section 5.1 (page C-11), pitting of stainless steel in an outdoor environment at St. Lucie depends on its location within the plant site. Experience at St. Lucie has identified pitting and SCC in the non-stress-relieved, heat-affected zone regions of weld joints of stainless steel piping located in the ECCS pipe tunnels that are exposed to the site's marine environment (LRA Table 3.2-2, page 3.2-19). The applicant stated that the terms "tunnels" and "trenches" are synonymous at St. Lucie. Components located in the ECCS trenches at St. Lucie have greater susceptibility to pitting and cracking due to their potential for increasing external contamination. These trenches are located in proximity to the discharge canals on the ocean side of the plant. The turbulence of ocean water at the plant discharge promotes increased chloride concentrations in the air and its chloride deposition on plant equipment located at low points in the proximity of the discharge canals. Because the ECCS trenches are low points and covered throughout most of their length, components located in the trenches tend to collect chlorides and do not have the benefit of periodic rainfalls that rinse the surfaces free of contaminants. Components located above ground elevation or in open trenches/pits (such as component cooling water stainless steel components) which are exposed to an outdoor environment (i.e., including rainfall) have not experienced SCC. Therefore, the applicant concluded that the potential for external pitting and cracking due to SCC at St. Lucie depends upon the localized environment of the components.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.1-2 clarifies and satisfactorily resolves this item because the applicant explained the differences between the outdoor environment and the outdoor environment (ECCS pipe tunnel) and also explained how this difference leads to differences in aging effects which are validated by the plant operating experience.

For carbon steel bolting exposed to outdoor, indoor-not-air-conditioned, and containment air environments, no aging effects are identified in Table 3.3-1. By letter dated July 1, 2002, the staff requested, in RAI 3.3-1, that the applicant provide a basis for not considering aging effects on bolting from exposure to these environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER. The staff concluded that this RAI is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the CVCS SSCs to the environments described in Section 2.3.3.1 and Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant identified the applicable aging effects that are appropriate for the combination of materials and environments of concern.

3.3.1.2.2 Aging Management Program

In Table 3.3-1, pages 3.3-13 through 3.3-17, of the LRA, the applicant credited the following AMPs for managing the aging effects in the CVCS system:

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.4 of this SER.

Based on its review of LRA Tables 3.3-1, the staff concludes that the AMPs identified above will effectively manage the aging effects of the CVCS so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.3 Conclusion

The staff reviewed the information in Section 2.3.3.1, Table 3.3-1 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the CVCS will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.4-1, the staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the CVCS as required by 10 CFR 54.21(d).

3.3.2 Component Cooling Water

3.3.2.1 Summary of Technical Information in the Application

The component cooling water (CCW) system removes heat from safety-related and non-safety-related components during normal and emergency operation. The CCW pumps circulate component cooling water through heat exchangers and coolers that are associated with other systems. The component cooling water heat exchangers transfer the heat from these systems to the intake cooling water. The CCW system is described in Sections 9.2.2 of the UFSARs for Units 1 and 2.

3.3.2.1.1 Aging Effects

Components of the CCW system are described in Section 2.3.3.2 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-2, pages 3.3-18 through 3.3-22, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), bolting, heat exchangers, tanks, orifices, piping, tubing and fittings, and sightglasses. The CCW system's, carbon steel, stainless steel, cast iron, aluminum brass, and aluminum bronze components are exposed to internal environments of raw water (salt water) or treated water and external environments of containment air, outdoor, indoor-not-air-conditioned, and leaking borated coolant environments. The corresponding aging effect requiring management is loss of material. The CCW aluminum brass heat exchanger tubes are exposed to raw water at the inside surface and treated water at the outside surface. The corresponding aging effect requiring management is fouling. The CCW bolting could be exposed to borated water leaking from an adjacent system or component containing borated coolant. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the CCW system:

- Chemistry Control Program
- Intake Cooling Water Inspection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Pipe Wall Thinning Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the CCW system will be adequately managed by these AMPs for the period of extended operation.

3.3.2.2 Staff Evaluation

The applicant described its AMR of the CCW system for license renewal in Section 2.3.3.2 and Section 3.3, Table 3.3-2, pages 3.3-18 through 3.3-22. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the CCW system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.2, Table 3.3-2, pages 3.3-18 through 3.3-22, and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In Appendix C, Section 4.1.1, the applicant stated that in an environment with extremely low oxygen content (less than 0.1 ppm), crevice corrosion is insignificant. Also the applicant stated that oxygen is required for pitting corrosion. The staff did not agree with this discussion of the role of oxygen in crevice and pitting corrosion because oxygen can be a contributor but is not needed for crevice and pitting corrosion of metal. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-1, the applicant to provide references to support its position. In its response dated September 26, 2002, the applicant stated that the oxygen criterion associated with loss of material due to crevice corrosion is based on the industry guidance document developed by the Babcock and Wilcox (BLW) Owners Group. This document references a

Corrosion and Wear Handbook for Water-Cooled Reactors by D.J. DePaul, McGraw-Hill, New York. The applicant also stated that it did not credit low oxygen with precluding crevice or pitting corrosion in the CCW system. Instead, it credited the control of contaminants under the Chemistry Control Program and the use of corrosion inhibitors (molybdate and nitrite) to preclude loss of material due to corrosion. The applicant stated that the Chemistry Control Program was developed in accordance with the guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," as described in LRA Appendix B, Subsection 3.2.5.2 (page B-33).

Furthermore, in its December 27, 2002, response to RAI B.3.2.5-2 concerning the Chemistry Control Program, the applicant stated that a review of St. Lucie plant-specific operating experience was performed as part of the aging management review process for CCW to identify any age-related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective Chemistry Control Program. The applicant noted that many CCW components have been inspected in the past as part of corrective maintenance or the preventive maintenance program (e.g., periodic pump overhauls). The applicant further stated, that during the past 12 months, more than 30 maintenance work orders were generated for Units 1 and 2 CCW that required disassembly or removal of components. These work orders included repairs on instrumentation and other isolation valves, flow control valves, and check valve and relief valve internal inspections throughout the system. A majority of these components (e.g., relief and isolation valves) entailed system locations where stagnant flow conditions exist. These locations are the likely candidates for pitting corrosion. The internal condition of the components has provided additional confidence that the Chemistry Control Program is effective.

In addition, the applicant stated that the St. Lucie maintenance procedures typically specify inspection criteria or reference plant quality instructions that specify internal cleanliness requirements. As an example, the maintenance procedure for relief valve removal and testing includes a visual inspection of valve and piping mating surfaces for corrosion and pitting. The applicant also stated that the maintenance procedures specify a Class C cleanliness requirement for CCW. A Class C cleanliness requirement permits a tightly adhered oxide film or red oxide coating, as well as small areas of light rust, but pitting would not be acceptable. The applicant further stated that any significant degradation identified during these inspections would have been documented under the plant corrective action program. Therefore, the applicant concluded that the Chemistry Control Program is an effective AMP for managing the aging effects as discussed.

On the basis of its review, the staff finds that the applicant’s response to RAI 3.3.2-1 clarifies and satisfactorily resolves the item because the applicant clarified that it credited the Chemistry Control Program to preclude pitting and crevice corrosion and because the plant operating experience verified the effectiveness of this AMP in managing the aging effects due to pitting and crevice corrosion.

The applicant did not identify cracking due to SCC as an aging effect for the CCW system components exposed to treated water. However, stainless steel components exposed to treated water can experience cracking due to SCC. In addition, field experience reported in Appendix C of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," indicates that if component cooling water is treated with nitrite as a corrosion inhibitor, carbon steel components exposed to treated water can experience IGSCC. Cracking of CCW piping is also reported in

NRC Licensee Event Report LER 91-019-00, "Loss of Containment Integrity due to Crack in Cooling Water Piping," October 26, 1991. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-2, the applicant to provide the basis for excluding cracking as an applicable aging effect for CCW system carbon and stainless steel components exposed to treated water. In its response dated September 26, 2002, the applicant referred to LRA Appendix C, Section 5.2 (page C-14), which states that SCC of stainless steel components is not considered an aging effect requiring management in a treated water environment with a temperature of less than 140°F. The operating temperature of CCW at St. Lucie Units 1 and 2 is less than 90°F, which is significantly below the SCC threshold temperature of 140 °F. The applicant also stated that a review of St. Lucie plant-specific operating experience did not identify SCC in stainless steel CCW components as an aging effect requiring management. Therefore, SCC is not an aging effect requiring management for CCW stainless steel components. The staff agrees with the applicant's response that the stainless steel CCW components are not susceptible to cracking due to SCC because their operating temperature is below 140 °F.

The applicant further stated that industry data have not identified SCC as a significant problem for carbon steel components. The industry experience reported in EPRI TR-107396, "Closed Cycle Water Chemistry Guideline," concerning IGSCC of carbon steel involved nitrite-treated cooling water systems with a nitrite concentration of up to 6000 mg/L (approximately 6000 ppm). The nitrite concentration of the CCW system at St. Lucie is maintained at 300 n 450 ppm. A review of St. Lucie plant-specific operating experience did not identify SCC in carbon steel components as an aging effect requiring management. Therefore, IGSCC is not an aging effect requiring management for carbon steel components. The applicant also stated that FPL has reviewed LER 91-019-00 for Surry Nuclear Station. Based on the applicant's review of this LER, the applicability to St. Lucie Units 1 and 2 could not be determined because a root cause was not identified in that LER.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.2-2 satisfactorily resolve this item because the applicant demonstrated that for CCW stainless steel and carbon steel components SCC is not an aging effect requiring management and because this conclusion is validated by plant operating experience.

The CCW heat exchanger components are internally exposed to the raw water environment on the tube side. These components include the aluminum brass heat exchanger tubes, aluminum bronze tubesheets, and carbon steel channels and doors. The aging effects for these components exposed to the raw water environment are identified in Table 3.3-2 and are discussed in Section 5.0 of Appendix C to the LRA. The raw water environment in the cooling canal is defined as salt water used as the ultimate heat sink. The applicant identified the applicable aging effects in this internal environment as loss of material (due to general, pitting, crevice, and galvanic corrosion, MIC, and selective leaching) and fouling. The applicant did not identify cracking due to SCC as an aging effect for the CCW system heat exchanger tubes exposed to raw water.

However, the operating experience at Turkey Point showed that the CCW heat exchanger tubes, which are made of aluminum brass and exposed to raw water on the tube side, are susceptible to SSC. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-3, the applicant to provide the basis for excluding cracking as an applicable aging effect for CCW heat exchanger tubes exposed to raw water. In its response dated November 27, 2002, the applicant stated that the metallurgical analysis of the failed Turkey Point CCW heat exchanger tubes revealed that the cracking was initiated from the inside diameter (raw water side) and was located in the tube roll transition zone of the tube sheet. The cracking was determined to be transgranular stress corrosion cracking (TGSCC) and was caused by the use of a new chemical injection system and the absence of sacrificial anodes. The tubes were replaced, the chemical injection system was removed from service, and zinc anodes were installed to prevent a recurrence.

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

On the basis of its review, the staff finds that the applicant’s response to RAI 3.3.2-3 satisfactorily resolves this issue because the applicant demonstrated that cracking due to SCC is not an aging effect requiring management for the CCW system heat exchanger tubes exposed to raw water.

The air/gas environment is an applicable internal environment for the carbon steel surge tanks, valves, piping and fittings, and Unit 1 sightglasses, and Unit 2 sightglasses (stainless steel). The applicant did not identify any aging effects of these components in the air/gas environment. The aging effects associated with exposure to the air/gas environment are identified in Table 3.3-2 and are discussed in Section 4.1.3, "Air/Gas," of Appendix C to the LRA. Several air/gas environment descriptions are provided for each of the air/gas environments found in the plant. Aging effects for CCW system components exposed to the air/gas environment depend in part, on the type of air/gas environment, the operating temperature, and the water content. By letter dated July 1, 2002, the staff requested, in RAI 3.3.2-4, that the applicant provide the characteristic parameters of the air/gas environments applicable to the components found in the CCW system and to provide the bases by which the determination of no aging effects requiring management was made for all the components exposed to the air/gas environment. In its response dated November 27, 2002, the applicant stated that the air/gas internal environment identified in LRA Table 3.3-2 (pages 3.3-18 and 3.3-19) applies to the CCW surge tanks and associated valves, piping and fittings located above the normal tank water level. This air/gas environment constitutes the atmospheric air of the surroundings (i.e., "indoor-not-air-conditioned" as defined in LRA Appendix C, Section 4.1.3, page C-8).

The applicant also stated that the AMR of the internal surfaces of the carbon steel CCW surge tanks exposed to an air/gas environment identified general corrosion as a potential aging mechanism. Based on the location of these tanks and the limited air exchange provided by the 2" tank vents, aggressive chemical species will not be present and significant pitting is not expected. Additionally, these tanks are internally coated. The applicant stated that a calculation was performed to analyze whether the 80-mil design corrosion allowance for these tanks will accommodate any potential internal corrosion. Utilizing conservative corrosion rates from Tables 6-1 and F-1 a Metals and Ceramics Information Center (MCIC) report, "Corrosion of Metals in Marine Environment" (July 1986) by J.A. Beavers, G.H. Koch, and W.E. Berry, the worst-case internal loss of material is calculated to be 76 mils (3 mils/yr x 8 yr + 1 mil/yr x 52 yrs) over the life of the plant. These corrosion rates are based upon comprehensive evaluations of corrosion damage to steel exposed to the tropical atmosphere in the Panama

Canal Zone. In addition, the applicant stated that the corrosion rate decreases with time due to the buildup of an oxidation layer, which will tend to provide some protection of the bare metal underneath. The use of this corrosion rate assumes no preventive measures (i.e., existing coatings) have been implemented since original installation and thus incorporates inherent design margin. Based on these results, the minimum required design wall thickness of the tanks is maintained. Therefore, loss of material due to corrosion of the internal surfaces of the upper portion of the CCW surge tanks, which is exposed to an air/gas environment, is not an aging effect requiring management. The applicant also stated that plant operating experience supports this conclusion.

The applicant further stated that the AMR of the internal surfaces of the small diameter carbon steel vent valves and schedule 80 pipe/fittings associated with the level switches/sightglasses of the CCW surge tanks exposed to an air/gas environment identified general corrosion as a potential aging mechanism. As discussed above, these tanks are located inside buildings and are vented by a 2" vent valve. There is limited air exchange through the vent valve. Therefore, aggressive chemical species will not be present and significant pitting is not expected. The rate of general corrosion is expected to be low. However, even assuming a conservative corrosion rate of 76 mils in 60 years (as discussed above), loss of pressure boundary integrity will not occur because adequate wall thickness will remain. The approximate wall thickness of 1" schedule 80 piping is 180 mils. The wall thickness of components, such as valves, is even greater. The minimum required wall thickness for these components is 2 mils. Therefore, the remaining wall thickness of 104 mils is more than adequate to meet design requirements, and adequate corrosion allowance exists for these components. Additionally, a review of St. Lucie plant-specific operating experience did not identify internal corrosion of these components as an aging effect requiring management. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the CCW surge tanks (which are exposed to an air/gas environment) is not an aging effect requiring management. The staff has reviewed Tables 6-1 and F-1 of the MCIC report referenced by the applicant and determined that the corrosion rates used by the applicant are conservative. According to the data in these tables, the corrosion rate reduces from 2.8 mils for the first year to 1.1 mils for the eighth year (12.6 mils total for 8 years).

On the basis of its review, the staff finds that the applicant’s response to RAI 3.3.2-4 satisfactorily resolves this issue because the applicant used a conservative corrosion rate to conclude that loss of material due to corrosion is not an aging effect requiring management for these CCW components and because the plant-specific operating experience supports this conclusion.

The CCW system contains some carbon steel components (e.g., CCW surge tanks, pumps, heat exchanger shells, valves, piping/fittings) and bolting that are externally exposed to outdoor, indoor-not-air-conditioned and containment air environments. The applicant has identified loss of material as an aging effect for all carbon steel components except bolting exposed externally to these environments. For carbon steel bolting exposed to outdoor, indoor-not air conditioned, and containment air environments, no aging effects are identified in Table 3.3-1. By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to these environments. The staff’s evaluation of the applicant’s response is documented in Section 3.3.17.1 of this SER, and the issue is characterized as resolved.

A few components in the CCW system have external surfaces that may be exposed to borated water leaks. By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response, documented in Section 3.3.17.2 of the SER, concluded that the issue is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the RAIs, the staff finds that the aging effects that result from contact of the CCW system SSCs with the environments described in Section 2.3.3.2 and Table 3.3-2 (pages 3.3-18 through 3.3-22) of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified for the combination of materials and environments listed.

3.3.2.2.2 Aging Management Programs

In Table 3.3-2, pages 3.3-18 through 3.3-22, of the LRA, the applicant credited the following AMPs for managing the aging effects in the CCW system:

- Chemistry Control Program
- Intake Cooling Water Inspection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Pipe Wall Thinning Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

The Chemistry Control Program, Galvanic Corrosion Susceptibility Inspection Program, Pipe Wall Thinning Inspection Program, Systems and Structures Monitoring Program, and Boric Acid Wastage Surveillance Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

The Intake Cooling Water Inspection Program is credited with managing the aging effects of several components in auxiliary systems and is, therefore, considered a system-specific AMP. The staff's evaluation of the Intake Cooling Water Inspection Program is described in Section 3.3.0.2 of this SER.

Based on its review of LRA Table 3.3-2, the staff concludes that the AMPs identified above will effectively manage the aging effects of the CCW system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3 Conclusion

The staff reviewed the information in Section 2.3.3.2 and Table 3.3-2 of the LRA and the additional information included in the applicant's responses to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the CCW system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that, with the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the CCW required by 10 CFR 54.21(d).

3.3.3 Demineralized Makeup Water (Unit 2 Only)

3.3.3.1 Summary of Technical Information in the Application

The demineralized makeup water provides makeup water to various systems throughout the plant. The intended function of the components in the demineralized makeup water system is to maintain pressure boundary integrity. Details of the demineralized makeup water system are described in the Unit 2 UFSAR, Section 9.2.3.

3.3.3.1.1 Aging Effects

Components of the demineralized makeup water system are described in Section 2.3.3.3 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-3, page 3.3-23, of the LRA lists individual components of the system including stainless steel valves (pressure boundary only), piping, and fittings and carbon steel bolting (mechanical closures). Stainless steel components are identified as subject to loss of material from exposure to treated water. Exposure of stainless steel components to a non-air-conditioned environment has no aging effects. Exposure of carbon steel bolting to a non-air-conditioned environment has no aging effects.

3.3.3.1.2 Aging Management Programs

The Chemistry Control Program is utilized to manage aging effects in the demineralized makeup water system. This AMP is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the demineralized makeup water system will be adequately managed by this AMP for the period of extended operation.

3.3.3.2 Staff Evaluation

The applicant described its AMR for the demineralized makeup water system for license renewal in Section 2.3.3.3, Section 3.3, and Table 3.3-3 (page 3.3-23) of the LRA. The process of identifying aging effects is summarized in Appendix C of the LRA, and a description of the AMP is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the demineralized makeup water system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.3, Table 3.3-3 (page 3.3-23), and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER, and the issue is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the demineralized makeup water system SSCs with the environments described in Section 2.3.3.3 and Table 3.3-3 (page 3.3-23) of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.3.2.2 Aging Management Programs

In Table 3.3-3 on page 3.3-23 of the LRA, the applicant credited the Chemistry Control Program for managing the aging effects in the demineralized makeup water system.

This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-3, the staff concludes that the AMP identified above will effectively manage the aging effects of the demineralized makeup water system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.3 Conclusion

The staff reviewed the information in Section 2.3.3.3 and Table 3.3-3 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the demineralized makeup water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that, with the exception of confirmatory item 3.0.2.2-1, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the demineralized makeup water system as required by 10 CFR 54.21(d).

3.3.4 Diesel Generators and Support Systems

3.3.4.1 Technical Information in the Application

The diesel generators and support systems provide AC power to the onsite electric distribution system to ensure the capability for a safe and orderly shutdown. The diesel generators and support systems consist of the diesel generators, air intake and exhaust system, air start system, fuel oil system, lube oil system, and cooling water system. Details of the diesel generators are described in the Unit 1 UFSAR, Section 8.3, and the Unit 2 UFSAR, Section 8.3. Details of the diesel generator support systems are described in Sections 9.5 of the UFSARs for Units 1 and 2.

3.3.4.1.1 Aging Effects

Components of the diesel generators and support systems are described in Section 2.3.3.4 of the LRA as being within the scope of license renewal and subject to an AMR. In Table 3.3-4, (pages 3.3-24 through 3.3-30) of the LRA, the applicant lists individual components of the system including diesel oil storage tanks, day tanks, pumps, valves, air start motors (pressure boundary only), heat exchangers, silencers, flame arrestors, filters, strains, flexible hoses, expansion joints, orifices, thermowells, sightglasses, piping, tubing, and fittings.

The components in the air intake and exhaust system are fabricated from carbon steel, polyester/rubber, rubber, and stainless steel. These components are exposed to an internal environment of air/gas and an external environment of indoor-not-air-conditioned. Loss of material is identified as an applicable aging effect for the carbon steel, polyester/rubber, and rubber components exposed to an air/gas internal environment. Cracking is identified for the polyester/rubber and rubber components exposed to an air/gas internal environment. No aging effect is identified for the stainless steel components exposed to air/gas internal environment. Loss of material is identified as an applicable aging effect for the carbon steel, polyester/rubber, and rubber components exposed to external indoor-not-air-conditioned environment. Cracking is identified for the polyester/rubber and rubber components exposed to external indoor-not-air-conditioned environment. No aging effect is identified for the stainless steel components exposed to external indoor-not-air-conditioned environment.

The components in the air start system are fabricated from carbon steel, stainless steel, aluminum alloy, and copper alloy. The air start system components are exposed to an internal environment of air/gas and an external environment of indoor-not-air-conditioned. No applicable aging effect is identified for the carbon steel, stainless steel, aluminum alloy, and copper alloy components exposed to the internal air/gas environment. Loss of material is identified as an aging effect for the carbon steel components exposed to an external environment of indoor-not-air-conditioned.

The components in the fuel oil system are fabricated from carbon steel, stainless steel, bronze, copper, and aluminum. These components are exposed to an internal environment of fuel oil and air/gas. Loss of material is identified as an aging effect for the carbon steel, stainless steel, bronze, copper, and aluminum components exposed to an internal environment of fuel oil. Loss of material is identified as an aging effect for the carbon steel fuel oil tanks exposed to an air/gas environment due to the potential for moisture contamination. Loss of material is identified as an aging effect for the Unit 1 carbon steel fuel oil tanks exposed to an external environment of outdoor and for the Unit 2 carbon steel fuel oil tanks exposed to external environment of indoor- not-air-conditioned.

The components in the lube oil system are fabricated from carbon steel, cast iron, stainless steel, brass, bronze, aluminum, and glass exposed to an internal environment of lube oil, treated water, and air/gas. Loss of material and fouling are identified as aging effects for the carbon steel, cast iron, stainless steel, brass, bronze, aluminum, and glass components exposed to treated water (other) internal environment. No aging effect is identified for those components exposed to lube oil or air/gas internal environment. Loss of material is identified as an applicable aging effect for the carbon steel and cast iron components exposed to an external environment of indoor-not-air-conditioned.

The components in the cooling water system are fabricated from carbon steel, brass, copper, stainless steel, rubber, and Plexiglas exposed to treated water. Loss of material, fouling, and cracking are identified as aging effect for the carbon steel, brass, copper, and stainless steel components exposed to a treated water internal environment. Cracking is identified as an aging effect for rubber and Plexiglas components exposed to a treated water internal environment. No aging effect is identified for any components exposed to internal air/gas environments. Loss of material is identified as an aging effects for the carbon steel, brass, copper, stainless steel, rubber, and Plexiglas cooling water system components exposed to an indoor- not-air-conditioned external environment. Cracking is identified as an aging effect for the rubber and Plexiglas components exposed to an indoor-not-air-conditioned external environment. Fouling is identified as an aging effect for the cooling water radiator fins exposed to an indoor-not-air-conditioned external environment.

3.3.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the diesel generators and support systems:

- Galvanic Corrosion Susceptibility Inspection Program
- System and Structure Monitoring Program
- Fuel Oil Chemistry Program
- Closed Cycled Cooling Water System Chemistry Program
- Periodic Surveillance and Preventive Maintenance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generators and support systems will be adequately managed by these AMPs for the period of extended operation.

3.3.4.2 Staff Evaluation

The applicant described its AMR for the diesel generators and support systems for license renewal in Section 2.3.3.4, Section 3.3, and Table 3.3-4 (pages 3.3-24 through 3.3-30) of the LRA. The process of identifying the aging effects is summarized in Appendix C of the LRA. Descriptions of the AMPs are provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generators and support systems will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.4, Table 3.3-4 (pages 3.3-24 through 3.3-40), and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In Section 9.5.6.3, "System Evaluation," on page 9.5-12b of the Unit 2 UFSAR, the applicant stated that the air receiver for the air start system of the emergency diesel generator collects moisture to preclude fouling of the air start valve with moisture and contamination.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-1, the applicant to provide justification for not identifying loss of material as an aging effect for the carbon steel, aluminum alloy, and copper alloy air start system components that are exposed to the internal moist air environment. In its response dated September 26, 2002, the applicant stated that in Table 3.3-4 (page 3.3-28) of the LRA, the air start and intake system internal environment for the Unit 2 startup air tanks (and associated valves, piping and fittings) was incorrectly identified as dry air/gas. Since the Unit 2 air start system does not have air dryers, the startup air tanks and associated components are actually exposed to moist air. Although the material of these components is stainless steel and thus not subject to general corrosion, they are potentially susceptible to loss of material due to pitting corrosion. As stated in Section 9.5.6.3 of the Unit 2 UFSAR, the air receiver for the air start system of the emergency diesel generator collects moisture to preclude fouling of the air start valve with moisture and contamination. These air tanks are periodically blown down to remove moisture. Therefore, Table 3.3-4 (page 3.3-28) has been corrected to indicate a wetted air/gas environment and to credit the Periodic Surveillance and Preventive Maintenance Program. A review of St. Lucie plant-specific operating experience has not identified loss of material in the Unit 2 air start system.

The applicant further stated that based upon moisture removal by periodic blowdown of the startup air tanks, the components downstream of the tanks are not subject to loss of material because the internal air/gas environment for these components is considered dry. The components downstream of the startup air tanks are made of stainless steel or aluminum. There are no copper alloy or carbon steel components in the Unit 2 air start and intake system. Table 3.3-4 (page 3.3-28) of the LRA is revised to incorporate the information that the aging effect of stainless steel startup air tanks, drain piping, and valves (Unit 2 only) in an air/gas (wetted) environment is loss of material and the AMP is the Periodic Surveillance and Preventive Maintenance Program.

On the basis of its review, the staff finds that the applicant’s response clarifies and satisfactorily resolves this item because the applicant corrected Table 3.3-4 of the LRA to indicated a “wetted air/gas” environment and credited the Periodic Surveillance and Preventive Maintenance Program with managing the effects of aging for the components identified in RAI 3.3.4-1.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-2, the applicant to provide justification for not identifying loss of material as an aging effect for air start system components fabricated from aluminum alloy or copper alloy exposed externally to an indoor-not-air-conditioned environment. In its response dated September 26, 2002, the applicant stated that, as discussed in LRA Appendix C, Section 5.1 (page C-11), and based upon industry guidance developed by the B&W Owners Group, both aluminum and copper alloys have high resistance to corrosion in atmospheric environments. As a result, no external aging effects requiring management were identified for these components. This conclusion is supported by a review of St. Lucie plant-specific operating experience which identified no instances of loss of material for the air start system components fabricated from aluminum or copper alloys exposed to an indoor-not-air-conditioned external environment .

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant has demonstrated that both aluminum and copper alloys have high resistance to corrosion in atmospheric environments and are not subject to loss of material. These findings are validated by the plant operating experience.

In Table 3.3-4 on page 3.3-33 of the LRA, the applicant identifies loss of material as a potential aging effect of the carbon steel fuel oil tanks exposed to an air/gas environment, as a result of the potential for moisture contamination. By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-3, the applicant to provide justification for not identifying loss of material for the carbon steel day tanks, which are also exposed to the same air/gas environment. In its response dated September 26, 2002, the applicant stated that the Unit 1 diesel oil storage tanks (DOSTs) are large vented tanks exposed to an outdoor environment. The Unit 2 DOSTs are inside a missile shield enclosure and are exposed to an indoor-not-air-conditioned external environment. Because of the large surface areas exposed to ambient temperature changes, these tanks are susceptible to condensation on the inside surfaces of the air/gas space. The condensation collects in the tank bottoms and must be periodically drained off. The day tanks, however, are small tanks and are located inside the emergency diesel generator buildings. They do not experience large ambient temperature changes and are not subject to significant condensation. Additionally, due to periodic testing of the diesel generators, the fuel in these tanks is consumed and replenished frequently, and therefore, collection of moisture is not anticipated. Also, the actual day tank internal environment is fuel oil vapor that protects the internal surfaces from corrosion. Therefore, loss of material is not an aging effect requiring management for the diesel generator fuel oil system internal air/gas environments, with the exception of the DOSTs.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue because the applicant has demonstrated that these day tanks are located inside the buildings and are not subject to significant condensation. In addition, collection of moisture is not anticipated in the day tanks.

In Table 3.3-4 on page 3.3-26 of the LRA, the applicant states that plant experience shows a history of loss of material as a result of corrosion of the copper and aluminum cooling water radiator fins in the cooling water system exposed to an indoor-not-air-conditioned environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.4-4, the applicant to explain why other copper and aluminum alloy components exposed to indoor or outdoor environments in the diesel generators and support systems are not subject to aging effects requiring aging management. These components include tubing/fittings, air start motors, air start motor lubricators, frame arrestors (in an outdoor environment), and filter housings. In its response dated September 26, 2002, the applicant stated that there has been no St. Lucie plant-specific experience that identifies loss of material as an aging effect for other cooling water system components fabricated from aluminum alloy or copper alloy exposed to an indoor-not-air-conditioned external environment. According to LRA Appendix C, Section 5.1 (page C-11), and widely available engineering sources, both aluminum and copper alloys are highly corrosion resistant in nonaggressive environments and have good corrosion resistance in atmospheric environments. However, St. Lucie plant-specific operating experience has identified loss of material of the radiator fins that ultimately resulted in replacement of the radiator cores. This can be attributed to the corrosion rate of the fins. Per the MCIC report "Corrosion of Metals in Marine Environments," J. A. Beavers, G. H. Koch, W.E. Berry, MCIC Report, July 1986, the corrosion rate for copper is 0.16 mil/yr and the corrosion rate for aluminum is 0.30 mil/yr. In most circumstances, this is an acceptable corrosion rate. However, due to the small thickness of the fins, the corrosion rate is more significant. Additionally, the radiator fins tend to filter and concentrate contaminants during diesel operation providing a more aggressive environment for corrosion. Therefore, loss of material is an aging effect requiring management for the radiator fins, as identified in LRA Table 3.3-4, page 3.3-26.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant demonstrated that the other copper and aluminum alloy components in the diesel generators and support systems exposed to indoor or outdoor environments are highly corrosion resistant in non-aggressive environments and are not subject to aging effects requiring aging management. In addition, the conclusions are validated by the plant operating experience.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER, and the issue is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the diesel generators and support systems SSCs with the environments described in Section 2.3.3.4 and Table 3.3-4 (pages 3.3-24 through 3.3-40) are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.4.2.2 Aging Management Programs

In Table 3.3-4 (pages 3.3-24 through 3.3-40) of the LRA, the applicant credited the following AMPs for managing the aging effects in the diesel generators and support systems:

- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Fuel Oil Chemistry Program
- Closed Cycle Cooling Water System Chemistry Subprogram
- Periodic Surveillance and Preventive Maintenance Program

The Galvanic Corrosion Susceptibility Inspection Program, the Systems and Structures Monitoring Program, the Closed Cycle Cooling Water System Chemistry Subprogram, and the Periodic Surveillance and Preventive Maintenance Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff's review of these common AMPs is documented in Section 3.0.5 of the SER. The Fuel Oil Chemistry Program is credited with managing the aging effects of several components in auxiliary systems and is, therefore, considered a system-specific AMP. The staff's evaluation of the Fuel Oil Chemistry Subprogram is described in Section 3.3.0.1 of this SER.

Based on its review of LRA Table 3.3-4, the staff concludes that the AMPs identified above will effectively manage the aging effects of the diesel generators and support systems so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.3 Conclusion

The staff reviewed the information in Section 2.3.3.4 and Table 3.3-4 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generators and support systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that, with the exception of confirmatory items 3.0.2.2-1 and 3.0.5.1-1, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the diesel generators and support systems as required by 10 CFR 54.21(d).

3.3.5 Emergency Cooling Canal System

3.3.5.1 Summary of Technical Information in the Application

The emergency cooling canal system admits water from Big Mud Creek to provide the ultimate heat sink for St. Lucie Units 1 and 2. The emergency cooling canal and ultimate heat sink dam, which is located between the intake canal and Big Mud Creek, are included in the civil/structural screening described in Subsections 2.4.2.9 and 2.4.2.14 respectively, of the LRA. Details of the emergency cooling canal system are described in Sections 9.2.7 of the UFSARs for Units 1 and 2.

3.3.5.1.1 Aging Effects

In Section 2.3.3.5 of the LRA, the applicant describes the components of the emergency cooling canal system as being within the scope of license renewal and subject to an AMR. In Table 3.3-5 on page 3.3-41 of the LRA, the applicant lists individual components of the system including aluminum bronze valves, carbon steel piping and fittings, and carbon steel bolting. The aluminum bronze and carbon steel components that are exposed to raw water n salt water are subject to loss of material due to corrosion, pitting, and erosion. Exposure of carbon steel components to embedded/encased environments has no aging effects.

3.3.5.1.2 Aging Management Programs

Periodic Surveillance and Preventive Maintenance Program is utilized to manage aging effects in the emergency cooling canal system. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the emergency cooling canal system will be adequately managed by this AMP for the period of extended operation.

3.3.5.2 Staff Evaluation

The applicant described its AMR of the emergency cooling canal system for license renewal in Section 2.3.3.5, Section 3.3, and Table 3.3-5 (page 3.3-41) of the LRA. The process of identification of the aging effects is summarized in Appendix C of the LRA. A description of the AMP is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the emergency cooling canal system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.5, Table 3.3-5 (page 3.3-41), and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review. By letter dated July 1, 2002, the staff issued RAI 3.3-3, pertaining to the chloride-related corrosion in the embedded/encased carbon steel piping/fitting. The staff's evaluation of the applicant's response, documented in Section 3.3.17.3 of this SER, concluded that the issue is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the emergency cooling canal system SSCs with the environments described in Section 2.3.3.5 and Table 3.3-5 (page 3.3-4) are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.5.2.2 Aging Management Programs

In Table 3.3-5, page 3.3-41 of the LRA, the applicant credited the Periodic Surveillance and Preventive Maintenance Program with managing the aging effects in the emergency cooling canal system. This AMP is also credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.5.9 of this SER.

Based on its review of LRA Table 3.3-5, the staff concludes that the AMP identified above will effectively manage the aging effects of the emergency cooling canal system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation.

3.3.5.4 Conclusion

The staff reviewed the information in Section 2.3.3.5 and Table 3.3-5 of the LRA and the additional information included in the applicant's response to the above RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the emergency cooling canal system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the emergency cooling canal system as required by 10 CFR 54.21(d).

3.3.6 Fire Protection

3.3.6.1 Summary of Technical Information in the Application

The fire protection systems protect plant equipment to ensure safe plant shutdown in the event of a fire. This section addresses the fire protection systems that are part of the auxiliary ystems. The fire-rated assemblies are included in the civil/structural aging management review of the LRA. They are discussed and evaluated in Section 3.5 of this SER.

The fire protection systems consist of two fire water supply systems that supply city water to the standpipe and hose station systems, the automatic fire suppression systems, and the plant fire hydrants in various areas of the plant for firefighting purposes. Each fire water supply system consists of a storage tank, motor-driven fire water pumps, isolation and control valves, and the 12-inch cement-lined cast iron underground pipe that loops around the plant. The fire protection systems consist of four types of fire suppression systems. The pre-action sprinkle systems are located indoors to protect safety-related systems. The wet pipe systems are located in the turbine building. The fixed water spray systems are located in the yard to protect various oil storage tanks and transformers. The halon system is located in the reactor auxiliary building to protect the cable spread room equipment. The reactor coolant pump oil collector system collects leaking reactor coolant pump lube oil to a collection tank. Details of the fire protection systems are described in Unit 1 UFSAR, Section 9.5A, Section 3.1.3, and Unit 2 UFSAR Section 9.5A, Section 3.1.3.

3.3.6.1.1 Aging Effects

Components of the fire protection systems are described in Section 2.3.3.6 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-6, pages 3.3-42 through 3.3-47 of the LRA, lists individual components of the system including city water storage tanks, fire water pumps, valves, piping, hydrants, tubing/fittings, sprinkler heads, vortex breakers, and filters. Loss of material is identified as an applicable aging effect for the carbon steel, cast iron, copper alloy, and stainless steel exposed to an internal environment of raw water (city water). Loss of material is also identified as an applicable aging effect for the carbon steel city water storage tanks because of the humid air in the lower portion of the tanks. No aging effect is identified for the carbon steel, cast iron, galvanized carbon steel, copper alloy, stainless steel, aluminum, and glass components exposed to the atmosphere air/gas or lube oil air/gas environments. No aging effect is identified for the carbon steel, stainless steel, aluminum, and glass components exposed to the lube oil environment.

Loss of material is identified as an applicable aging effect for the carbon steel and cast iron components exposed to external outdoor environment. No aging effect is identified for the copper alloy and stainless steel components exposed to the outdoor environment. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to the external environment of containment air. No aging effect is identified for the stainless steel, aluminum, and glass components exposed to containment air environment. Loss of material is identified as an applicable aging effect for the carbon steel components exposed to an external environment of borated water leaks. Loss of material is identified as an applicable aging effect for the cast iron components exposed to external environment of buried condition. No aging effect is identified for the cast iron components to the external environment of embedded/encased. The applicable aging effects in the indoor-not-air-conditioned environment include loss of material for the carbon steel and cast iron components. No aging effect is identified for the stainless steel, copper alloy, and the galvanized carbon steel components exposed to the external environment of indoor-not-air-conditioned.

3.3.6.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the fire protection system.

- Fire Protection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the fire protection systems will be adequately managed by these AMPs for the period of extended operation.

3.3.6.2 Staff Evaluation

In Section 2.3.3.6, Section 3.3, and Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, the applicant described its AMRs of the fire protection component. The process of identifying the aging effects is summarized in Appendix C of the LRA. A description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fire protection systems will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.6, Table 3.3-6 (pages 3.3-42 through 3.3-47), and the applicable sections in Appendix C of the LRA. During the review, the staff determined that additional information was needed to complete its review.

In Section B.3.2.8, "Fire Protection Program," on page B-39 of the LRA, the applicant states that the Fire Protection Program is credited with managing the aging effects of loss of material attributable to corrosion (including selective leaching).

By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-1, the applicant to identify those components and locations that are susceptible to leaching. In its response dated September 26, 2002, the applicant stated that as described in LRA Appendix C, Section 5.1 (page C-13), loss of material due to selective leaching (dealloying) has been identified as a potential aging effect for gray cast iron and certain brass or bronze materials. Specifically, brass and bronze with greater than 15 percent zinc, or aluminum bronze with greater than 8 percent aluminum are susceptible to dealloying. The fire protection system’s copper alloy components have a zinc content of less than 15 percent; therefore, these components are not susceptible to loss of material due to selective leaching. There are no aluminum bronze components in the fire protection system. For gray cast iron exposed to an internal environment of raw water n city water and an external environment of buried, loss of material due to selective leaching is an aging effect requiring management as shown in LRA Table 3.3-6, pages 3.3-42 and 3.3-45.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant identified the components susceptible to loss of material due to selective leaching.

The fire water supply system consists of a 12-inch, cement-lined, cast-iron underground pipe that loops around the plant. The cement lining may degrade due to cracking or spalling that may cause flow blockage in the piping. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-2, the applicant to explain why an AMR was not performed for the cement lining. In its response dated September 26, 2002, the applicant stated that the cement lining in the fire protection water supply (suppression water distribution) system does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). The cement lining performs the preventive function of minimizing the potential for corrosion. However, the cement lining is not credited with eliminating aging effects. The cement, or mortar, lining is per American Water Works Association (AWWA)/C104/A21.4. The thickness is nominally 1/16 inch. A review of St. Lucie plant-specific operating experience did not identify any instances of flow blockage of the fire protection suppression water distribution system due to piping lining failures. The applicant also stated that fire protection components are periodically flushed, performance tested, and inspected. Significant internal lining failures would be detected by changes in flow or pressure or by evidence of cement products during flushing of the system. Therefore, the applicant concluded that an AMR is not required for the cement lining of the fire protection suppression water distribution system.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant clarified that the cement lining in the fire protection water supply (suppression water distribution) system does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). The applicant also demonstrated that lining failures would be detected while flushing the system. Therefore, an AMR is not required for the cement lining of the fire protection suppression water distribution system.

The fire water supply system consists of a 12-inch, cement-lined, cast-iron, underground pipe that loops around the plant. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-3, the applicant to explain how the aging effect of loss of material as a result of corrosion is managed for the external surfaces of the buried pipe. In its response dated September 26, 2002, the applicant stated that the St. Lucie fire water supply (suppression water distribution) cast iron piping is buried in Class 1 fill and is located above ground-water elevation. Additionally, this piping is coated with a coal tar epoxy to minimize the potential for corrosion. The applicant also stated that it has considered external loss of material to be an aging effect requiring management for the fire water supply cast iron piping.

As indicated in Table 3.3-6 (page 3.3-45) of the LRA, the Fire Protection Program (LRA Appendix B, Section 3.2.8 page B-39) is credited with managing the external aging effect of loss of material for cast iron fire water supply piping. The fire water system is continuously pressurized and monitored. Any localized degradation of the external coating resulting in a corrosion cell would ultimately manifest itself in a leak in the piping. The resultant leakage would be detected by pressure monitoring instrumentation, and if the leak was large enough, a fire pump would automatically start indicating an unexpected system demand. Additionally, periodic performance testing under the Fire Protection Program is utilized to manage the external aging effects.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant demonstrated that the aging effect of loss of material in underground pipe will be adequately managed by the Fire Protection Program.

In Appendix B, Section B.3.2.8, of the LRA, the applicant stated that functional testing and flushing of the fire protection systems clears away internal scale and corrosion products that could lead to blockage or obstruction of the system. By letter dated July 1, 2002, the staff requested, in RAI 3.3.6-4, the applicant to discuss why Table 3.3.6 of the LRA does not include biofouling as an applicable aging effect. In its response dated September 26, 2002, the applicant stated that the fire protection systems are filled with water classified as raw water - city water. The city water has been rough-filtered to remove large particles and has been purified but conservatively classified as raw water for the purposes of the AMR. The applicant further stated that macro-organisms would not be found in this water, and therefore, biofouling is not an applicable aging effect for the fire protection systems.

On the basis of its review, the staff finds that the applicant's response clarifies and satisfactorily resolves this item because the applicant explained that macro-organisms would not be found in the city water and therefore, biofouling is not an applicable aging effect for the fire protection systems.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects that result from contact of the fire protection system SSCs with the environments, as described in Section 2.3.3.6 and Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

3.3.6.2.2 Aging Management Programs

In Table 3.3-6 (pages 3.3-42 through 3.3-47) of the LRA, the applicant credited the following AMPs with managing the aging effects in the fire protection systems:

- Fire Protection Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-6, the staff concludes that the AMPs identified above will effectively manage the aging effects of the fire protection system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.3 Conclusion

The staff reviewed the information in Section 2.3.3.6 and Table 3.3-6 of the LRA and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concludes that, with the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1 and 3.0.5.4-1, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the fire protection systems as required by 10 CFR 54.21(d).

3.3.7 Fuel Pool Cooling System

3.3.7.1 Summary of Technical Information in the Application

The fuel pool cooling system removes decay heat from the fuel pool by circulating water through the fuel pool heat exchangers during normal plant operation. The heat from the fuel pool is transferred to CCW. The applicant described the safety-related means of fuel pool cooling for Unit 1 as pool boiloff and system makeup from intake cooling water without forced circulation through the heat exchanger. For Unit 2, the applicant stated that the safety-related means of fuel pool cooling is recirculating through the fuel pool heat exchangers. As a backup, Unit 2 fuel pool cooling can be accomplished by pool boiloff and system makeup from intake cooling water. Details of the fuel pool cooling system are described in Unit 1 UFSAR, Section 9.1.3, and Unit 2 UFSAR, Section 9.1.3.

3.3.7.1.1 Aging Effects

Components of the fuel pool cooling system are described in Section 2.3.3.7 of the submittal as being within the scope of license renewal and subject to an AMR. Table 3.3-7, pages 3.3-48 through 3.3-49, of the LRA lists individual components of the system including stainless steel pumps, valves (pressure boundary only), heat exchangers, thermowells, piping, tubing, and fittings, carbon steel spent fuel pool heat exchanger shell, and tube support (Unit 2 only). Stainless steel components exposed to treated water and/or borated water are subject to the loss of material and fouling (inside diameter) aging effects. Carbon steel components exposed to treated water (borated and other as described in Section 4.1.1 of Appendix C of the LRA are subject to the loss of material aging effect.

3.3.7.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the fuel pool cooling system:

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the fuel pool cooling system will be adequately managed by these AMPs for the period of extended operation.

3.3.7.2 Staff Evaluation

The applicant described its AMR for the fuel pool cooling system for license renewal in Section 2.3.3.7 and Section 3.3, Table 3.3-7, of the LRA. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fuel pool cooling system will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.7.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.7, Table 3.3-7, pages 3.3-48 through 3.3-49, and the applicable sections in Appendix C of the LRA. The aging effects on the components exposed to the fuel pool cooling system environments as described in Section 2.3.3.7 and Table 3.3-7, are consistent with the industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects have been identified, and that the aging effects listed are appropriate for these combinations of materials and environments.

3.3.7.2.2 Aging Management Programs

In Table 3.3-7, of the LRA, the applicant credited the following AMPs with managing the aging effects in the fuel pool cooling system:

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are also credited with managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-7, the staff concludes that the AMPs identified above will effectively manage the aging effects of the fuel pool cooling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.7.3 Conclusion

The staff reviewed the information in Section 2.3.3.7 and Table 3.3-7 of the LRA. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the fuel pool cooling system, will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff also concluded that, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the fuel pool cooling system as required by 10 CFR 54.21(d).

3.3.8 Instrument Air

3.3.8.1 Summary of Technical Information in the Application

The instrument air system provides a reliable source of dry, oil-free air for pneumatic instruments and controls, and pneumatically operated valves. Instrument air contains both electric driven and diesel driven air compressors. The instrument air system utilizes several compressors, each having a separate inlet filter, aftercooler, and moisture separator. The turbine cooling water system cools the compressors. The instrument air compressors discharge to a header connected to an air receiver, air dryer, and filter assembly. The compressed air header is divided into branch lines supplying to different areas of the plant, e.g., CCW area, reactor auxiliary building, fuel handling areas, and the steam generator blowdown treatment facility. Details of the instrument air system are described in Unit 1 UFSAR Section 9.1.3 and Unit 2 UFSAR Section 9.1.3.

3.3.8.1.1 Aging Effects

Components of the instrument air system are described in Section 2.3.3.8 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-8, pages 3.3-51 through 3.3-58, of the LRA lists individual components of the system, including valves (pressure boundary only), flasks/tanks, filters, strainers, heat exchangers, orifices, piping, tubing, hoses, fittings, air receivers, air dryers, shells, and bolting. The carbon steel instrument air receivers, dryers, compressor cooler shells and tube sheets, valve bodies, silencers, accumulators, piping and fittings, and galvanized carbon steel piping and fittings are internally exposed to treated water or moist air/gas environment, and externally exposed to indoor-not-air-conditioned, outdoor, containment air, or leaking borated coolant environments. The corresponding aging effect requiring management is loss of material. The copper tubes and copper alloy tube sheets of compressor coolers, brass and bronze valve bodies, copper alloy sightglasses, stainless steel valve bodies, filters, and filter and strainer housings are internally exposed to moist air/gas environment. The corresponding aging effect requiring management is loss of material. The instrument air compressor cooler copper tubes are internally exposed to treated water or moist air/gas environment. The corresponding aging effect requiring management is fouling. The plastic valve bodies and rubber hoses are internally exposed to moist air/gas environment and externally exposed to indoor-not air-conditioned environment. The corresponding aging effect requiring management is cracking. The closure bolting could be externally exposed to borated coolant leaking from adjacent system or component containing borated coolant. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.8.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the instrument air system:

- Periodic Surveillance and Preventive Maintenance Program
- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the instrument air system will be adequately managed by these AMPs for the period of extended operation.

3.3.8.2 Staff Evaluation

The applicant describes its AMR of the instrument air for license renewal in Section 2.3.3.8 and Section 3.3, Table 3.3-8, of the LRA. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the instrument air systems will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.8.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.8, Table 3.3-8, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

The instrument air system components located downstream of the air dryer are internally exposed to dry air/gas environment. These components include valve bodies, piping and fittings, accumulators, tubing, thermowells, flexible hoses, rupture discs, filter and filter housings, strainers, and orifices. These components are fabricated from copper-alloy, brass, bronze, aluminum, carbon steel, galvanized carbon steel, and stainless steel. The applicant stated that the dry air/gas environment does not introduce any applicable aging effect on these components.

However, this may not be supported by the industry operating experience. As an example, NRC Information Notice (IN) 1987-28, Air System Problems at U.S. Light Water Reactors, indicated that a loss of decay heat removal and significant primary system heatup at Palisades in 1978 and 1981 were caused by water in the air system. This experience implied that the air/gas system downstream of the dryer may not be dry. By letter dated July 1, 2002, the staff requested, in RAI 3.3.8-1, the applicant to provide the technical basis for not identifying loss of material as an applicable aging effect for the components downstream of the air dryer. In its response dated September 26, 2002, the applicant stated that NRC IN 1987-28 and Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment" were reviewed during its AMR of instrument air. St. Lucie, like many other U.S. nuclear power plants, experienced general corrosion of its instrument air component internal surfaces early in its operating life. A review of St. Lucie plant-specific operating experience identified leak test failures and internal piping corrosion that occurred in the 1980s. The investigation of these problems demonstrated that the onset of general corrosion downstream of the air dryers was attributed to the ineffectiveness of the original air dryers in combination with the carbon steel construction of the system piping. To address these equipment problems, the instrument air dryers were replaced in 1989 with more effective desiccant dryers (including prefilter and after filters), and two new instrument air compressors were added with capacities and purification capabilities recommended by ANSI/ISA-S7.3, Quality Standard for Instrument Air, Instrument Society of America. Additionally, FPL aggressively pursued improved system performance via upgraded maintenance procedures, additional training of operators, and verification of the system design. Since its completion of corrective actions associated with Generic Letter 88-14, St. Lucie instrument air has met the required air quality requirements and has not experienced corrosion-related problems downstream of the instrument air dryers.

The applicant further stated that St. Lucie addressed air quality issues downstream of dryers in FPL's response to Generic Letter 88-14. This response included the following one-time verifications including (1) verification that actual instrument air quality is consistent with manufacturers recommendations for safety-related components, (2) verification that maintenance practices, emergency procedures, and training are adequate, and (3) verification that the design of the entire system, including air or other pneumatic accumulators, is in accordance with its intended function, which included testing of air operated valves.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.8-1 clarifies and satisfactorily resolves this item because the applicant has demonstrated that the instrument air dryer design change, maintenance procedure, and system design verification will ensure that loss of material is not an applicable aging effect for the instrument air components downstream of the air dryer.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not air conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the instrument air system SSCs to the environments described in Section 2.3.3.8 and Table 3.3-8, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.8.2.2 Aging Management Programs

In Table 3.3-8, of the LRA, the applicant credited the following AMPs for managing the aging effects in the instrument air system:

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

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-8, the staff concludes that the AMPs identified above will effectively manage the aging effects of the instrument air system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.3 Conclusion

The staff reviewed the information in Section 2.3.3.8 and Table 3.3-8 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the instrument air system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.5.1-1 and 3.0.5.4-1, the staff also concluded that, the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the instrument air system as required by 10 CFR 54.21(d).

3.3.9 Intake Cooling Water System

3.3.9.1 Summary of Technical Information in the Application

The intake cooling water (ICW) removes heat from component cooling water, turbine cooling water, and steam generator open blowdown system, and discharges it to the condenser discharge canal. Intake cooling water from the intake structure flows through basket strainers located at the inlets of the component cooling, turbine cooling, and steam generator open blowdown heat exchangers, passes through the tube side of the exchangers, and flows to the discharge canal. Additionally, ICW provides a safety-related makeup source for fuel pool cooling. Details of the ICW are described in Unit 1 UFSAR Section 9.2.1 and Unit 2 UFSAR Section 9.2.1.

3.3.9.1.1 Aging Effects

Components of the ICW system are described in Section 2.3.3.9 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-9, pages 3.3-59 through 3.3-64, of the LRA lists individual components of the system including pumps and valves (pressure boundary only), strainers, orifices, piping, tubing, fittings, thermowells, expansion joints, and bolting. The carbon steel and stainless steel valves and piping/fittings in main process lines and basket strainers are exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The carbon steel piping/fitting in the main process lines are exposed also to internal environment of air/gas. The corresponding aging effect requiring management is loss of material. The Monel orifices are exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The buried carbon steel piping/fittings are externally exposed to soil. The aging effect requiring management is loss of material. The submerged carbon steel piping/fittings (discharge) are exposed to external environment of raw water. The corresponding aging effect requiring management is loss of material. The aluminum brass heat exchanger tubes are exposed to internal environment of raw water. The corresponding aging effects requiring management are fouling and loss of material. The aluminum brass heat exchanger tubesheet is exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The carbon steel heat exchanger channels and doors are exposed to internal environment of raw water. The corresponding aging effect requiring management is loss of material. The carbon steel bolting is exposed to external environment of leaking borated coolant. The corresponding aging effect requiring management is loss of mechanical closure integrity. The stainless steel and Monel bolting is exposed to external environment of raw water-salt water. The corresponding aging effect requiring management is loss of mechanical closure integrity.

3.3.9.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the ICW system:

- Periodic Surveillance and Preventive Maintenance Program
- Intake Cooling Water Inspection Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the ICW system will be adequately managed by these AMPs for the period of extended operation.

3.3.9.2 Staff Evaluation

The applicant described its AMR of the ICW system for license renewal in Section 2.3.3.9 and Section 3.3 of the LRA. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ICW system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.9.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.9, Table 3.3-9, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

Several stainless steel components in the ICW system are externally exposed to indoor-not-air-conditioned environment. These components include pump and valve bodies, piping/fittings, tubing/fittings, and mechanical closure bolting. The applicant has identified loss of material as an applicable aging effect only for the pump bodies and not for any other stainless steel component. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-1, the applicant to provide technical basis for not identifying loss of material as an applicable aging effect for stainless steel piping/fittings and tubing/fittings in the ICW system externally exposed to indoor-not-air-conditioned environment. In its response dated September 26, 2002, the applicant stated that pitting corrosion has been identified as a potential aging mechanism for the external surfaces of the above ground stainless steel piping/fittings, tubing/fittings, orifices, and valves in the ICW system. Based on LRA Appendix C, Section 5.1 (page C-11), moisture must be present for pitting corrosion to occur. Stainless steel ICW components located in an indoor-not-air-conditioned environment (LRA Table 3.0-2, page 3.0-3) are not subject to moisture unless specifically identified in the LRA tables. Additionally, visual inspections of these components and St. Lucie plant-specific operating experience have not identified pitting

corrosion as an aging mechanism that could lead to loss of material. Therefore, loss of material due to corrosion is not an aging effect requiring management for these stainless steel components exposed to indoor-not-air-conditioned environment.
On the basis of its review, the staff finds that the applicant's response to RAI 3.3.9-1 clarifies and satisfactorily resolves this item because visual inspections and plant operating experience have not identified pitting corrosion causing loss of material at the external surface of these stainless steel ICW components.

Several bronze, aluminum bronze, and aluminum brass components in the ICW system are externally exposed to outdoor or indoor-not-air-conditioned environments. These components include pump and valve bodies, and piping/fittings. No aging effects are identified for these components which are exposed to outdoor or indoor-not air-conditioned environment. In Section 5.1 of Appendix C to the LRA, the applicant also stated that bronze and brass are considered susceptible to pitting when zinc content is greater than 15 percent and aluminum bronze is considered susceptible to pitting when the aluminum content is greater than 8 percent. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-2, the applicant to explain why loss of material is not an applicable aging effect for the bronze, aluminum bronze, and aluminum brass components in the intake cooling water system. In its response dated September 26, 2002, the applicant stated that the intent of LRA Appendix C, Section 5.1 (page C-11) is to indicate that moisture must be present for pitting to occur. Loss of material due to pitting corrosion is an applicable aging effect only if the bronze, brass, or aluminum bronze component is buried, submerged in fluid, or subject to wetting other than normal environment. The applicant further indicated that these components in the ICW system are not subject to external wetting.

On the basis of its review, the staff finds the applicant's response to RAI 3.3.9-2 acceptable because the ICW components addressed here are not subject to wetting externally and, therefore, are not susceptible to pitting corrosion.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-3 pertaining to the chloride-related corrosion in the embedded/encased carbon steel piping/fitting. The staff's evaluation of the applicant's response is documented in Section 3.3.17.3 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the ICW system SSCs to the environments described in Section 2.3.3.9 and Table 3.3-9, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.9.2.2 Aging Management Programs

In Table 3.3-9, of the LRA, the applicant credited the following AMPs for managing the aging effects in the ICW system:

- Periodic Surveillance and Preventive Maintenance Program
- Intake Cooling Water Inspection Program
- Systems and Structures Monitoring Program

The Periodic Surveillance and Preventive Maintenance Program and the Systems and Structures Monitoring Program are credited with managing the aging effects of several components in different structures and systems, and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER. The Intake Cooling Water Inspection Program is credited with managing the aging effects of several components in auxiliary systems, and is, therefore, considered to be a system-specific AMP. The staff's evaluation of the Intake Cooling Water Inspection Program is described in Section 3.3.9.2 of this SER.

The Systems and Structures Monitoring Program provides for visual inspection of external surfaces of the components for evidence of degradation or leakage. The description of this program is provided in Section 3.2.14, "Systems and Structures Monitoring Program," of Appendix B to the LRA. The detailed evaluation of this program is presented in Section 3.0.3.15 of this SER. The applicant relies on detection of leakage for managing loss of material on the inside surface of several components exposed to raw water. The applicant has performed evaluations that show that through-wall leakage equivalent to a sheared 3/4" instrument line, and an additional 100 gpm opening from another location, will not reduce the ICW flow to the CCW heat exchangers below design requirements. The staff's concern is that the presence of leakage from a component, however, would indicate that the component has lost its ability to perform its intended function, i.e., pressure boundary. By letter dated July 1, 2002, the staff requested, in RAI 3.3.9-3, the applicant to justify why the use of this program alone is adequate for managing loss of material at the inside surface of the components exposed to raw water. In its response dated November 27, 2002, the applicant stated that in addition to leak detection, it will employ the Intake Cooling Water System Inspection Program (LRA Appendix B, Subsection 3.2.20, page B-43) in addition to the Systems and Structures Monitoring Program (LRA Appendix B, Subsection 3.2.14, page B-57) for managing the aging effect of loss of material for valves, piping, and fittings at selected locations of ICW. Although the ICW crawl-through inspections do not include inspection of small bore piping components due to access limitations, the crawl-through inspections do inspect the connections between the small bore piping and large bore piping, which are the limiting locations for the small bore piping components. The applicant provides the following explanation of why these connections are the limiting locations. Originally the small-diameter piping was epoxy coated carbon steel piping. This piping have leaked in the past because of its exposure to salt water and resulting loss of material due to corrosion at the inside surface. As a result, the applicant has replaced 75 percent of these small-diameter carbon steel piping with the ones constructed of corrosion-resistant materials (monel, bronze, aluminum bronze). However, the connections of these replaced piping with the large bore piping have not been replaced. These connections are still the original epoxy-coated carbon steel. Therefore, these connections remain the bounding locations for the replaced piping.

In addition, the applicant provides the following justification for why the leak detection is adequate to maintain the intended function of the ICW System. Maintenance history shows that localized failures of cement lining result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage, which provides adequate time for repairs before the system function is degraded. For small valves, piping, and fittings, leakage does not affect the system function because the small size of these components limits the leakage. Plant operators walk down the ICW system as part of normal shift activities, and would note any leaks that were present. When leaks are identified, they are immediately documented under the corrective action program and receive prompt engineering evaluation and corrective actions. The operating and maintenance history of this equipment demonstrates that leakage for this equipment has not been significant. Thus, the applicant concludes that the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of intake cooling water.

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.9-3 clarifies and satisfactorily resolves this item because the applicant has demonstrated that the leakage detection, along with the inspections of all the carbon steel connections between the small- and large-diameter piping, would provide adequate management for loss of material at the inside surface of the small-diameter piping without degrading the ICW system function.

Based on its review of LRA Table 3.3-9, the staff concludes that the above-identified AMPs will effectively manage the aging effects of the ICW system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9.3 Conclusion

The staff reviewed the information in Section 2.3.3.9 and Table 3.3-9 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the ICW system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the ICW system as required by 10 CFR 54.21(d).

3.3.10 Miscellaneous Bulk Gas Supply System

3.3.10.1 Summary of Technical Information in the Application

The common miscellaneous bulk gas supply system consists of the hydrogen, carbon dioxide, and nitrogen systems. Various storage facilities and associated components are provided for Units 1 and 2 for supplying hydrogen, carbon dioxide, and nitrogen for plant operation. Hydrogen is stored in tube trailers and in bottles in the hydrogen storage facilities. The hydrogen storage facilities and distribution system are designed to comply with the Occupation

Safety and Health Administration (OSHA) requirements. Carbon dioxide is stored in bottles in the gas storage building, which is located adjacent to the hydrogen storage facility. The carbon dioxide system is designed to OSHA requirements. The nitrogen system supplies low-and high-pressure nitrogen to various systems and vessels which require cover gas. Bulk storage facilities for nitrogen are provided by a low-pressure nitrogen dewar with two compressors and a high-pressure tube trailer. In addition, a bank of cylinders supplies nitrogen gas for the nuclear steam supply system. The storage facility and the distribution piping of nitrogen system are designed to meet the OSHA requirements. Details of the common miscellaneous bulk gas supply ICW system are described in Unit 1 UFSAR Section 9.3.1.

3.3.10.1.1 Aging Effects

Components of the miscellaneous bulk gas supply system are described in Section 2.3.3.10 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-10, page 3.3-65, of the LRA lists individual components of the system including vessel, piping/fitting, and tubing/fitting, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal environment of air/gas and external environments of indoor-not-air-conditioned with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to indoor-not-air-conditioned and borated water leaks. Carbon steel components are identified as being subject to the internal environment of air/gas with no aging effects identified.

3.3.10.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the miscellaneous bulk gas supply system:

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the miscellaneous bulk gas supply system will be adequately managed by these AMPs for the period of extended operation.

3.3.10.2 Staff Evaluation

The applicant described its AMR of the miscellaneous bulk gas supply system for license renewal in Section 2.3.3.10 and Table 3.3-10. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the miscellaneous bulk gas supply system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.10.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.10, Table 3.3-10, and the applicable sections in Appendix C of the LRA. The aging effects that result from contact of the miscellaneous bulk gas supply system SSCs to the environments described in Section 2.3.3.10 and Table 3.3-10, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.10.2.2 Aging Management Programs

In Table 3.3-10, of the LRA, the applicant credited the following AMPs for managing the aging effects in the miscellaneous bulk gas supply system:

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-10, the staff concludes that the above identified AMPs will effectively manage the aging effects of the miscellaneous bulk gas supply system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10.3 Conclusion

The staff reviewed the information in Section 2.3.3.10 and Table 3.3-10 of the LRA. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the miscellaneous bulk gas supply systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.05.4-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the miscellaneous bulk gas supply systems as required by 10 CFR 54.21(d).

3.3.11 Primary Makeup Water

3.3.11.1 Summary of Technical Information in the Application

Primary makeup water provides treated, demineralized water for makeup to various systems throughout the St. Lucie Units 1 and 2 plants. Details of the primary makeup water system are described in Unit 1 UFSAR Section 9.2.5 and Unit 2 UFSAR Section 9.2.3.

3.3.11.1.1 Aging Effects

Components of the primary makeup water system are described in Section 2.3.3.11 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-11, pages 3.3-66 through 3.3-67, of the LRA lists individual components of the system including carbon steel tanks, stainless steel pumps, valves (pressure boundary only), piping, tubing, fittings, vortex breaker (Unit 2 only), orifices (Unit 2 only), nickel alloy piping (Unit 1 only), copper alloy valves, hose-station fittings, hose-station nozzles (Unit 2 only), and rubber expansion joints (Unit 2 only). Stainless steel components are identified as subject to loss of material aging effects due to exposure to treated water environments. Carbon steel components exposed to treated water and air/gas environments are subject to loss of material aging effect. Rubber components exposed to treated water and other environments are subject to cracking aging effects. Exposure of nickel alloy and copper alloy components to treated water environment has loss of material aging effects. Exposure of copper alloy components to air/gas environment has no aging effects.

3.3.11.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the primary makeup water system:

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the primary makeup water system will be adequately managed by these AMPs for the period of extended operation.

3.3.11.2 Staff Evaluation

The applicant described its AMR for the primary makeup water system for license renewal in Section 2.3.3.11and Section 3.3, Table 3.3-11. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the primary makeup water system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.11.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.11, Table 3.3-11, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

By letter dated July 1, 2002, the staff requested, in RAI 3.3.11-1, the applicant to provide additional information to clarify whether hardening is an applicable aging effect for the rubber materials of the expansion joints in the primary makeup water system, and to discuss how, if applicable, this aging effect will be managed. In its response dated September 26, 2002, the applicant stated that *Marks' Standard Handbook for Mechanical Engineers* (Tenth Edition, page 6-147) describes rubber that is exposed to an outdoor environment (air and sun) may become hard and brittle (embrittlement as defined on Page C-15 of LRA Appendix C, Section 5.2). The aging effect resulting from embrittlement and hardening is cracking. The applicant also stated that cracking is identified in LRA Table 3.3-11 as an aging effect requiring management for the rubber expansion joints of the Unit 2 primary makeup water system. This aging effect is adequately managed by the Systems and Structures Monitoring Program.

On the basis of its review, the staff finds the applicant’s response reasonable and adequate because the applicant has identified cracking as an applicable aging effect resulting from embrittlement and hardening for the rubber expansion joints of the Unit 2 primary makeup water system and this aging effect is managed by the Systems and Structures Monitoring Program.

The applicant identified loss of material as an applicable aging effect for the carbon steel primary water storage tank (Unit 2 only) because of the humid air due to water in the lower portion of the tanks. However, the applicant did not identify any aging effects for copper alloy components exposed to the internal air/gas environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.11-2, the applicant to describe the composition of the internal air/gas environment to which the fittings and nozzles of the hose station of Unit 2 are exposed, and to specify the level of humidity of this particular environment. The applicant was also requested to clarify whether loss of material is an applicable aging effect and to discuss how, if applicable, this aging effect will be managed.

In its response dated September 26, 2002, the applicant stated that the fittings and nozzles of the Unit 2 hose stations are exposed to internal air/gas environments consisting of the external environment (i.e., indoor-not-air-conditioned or containment air). These environments are defined in LRA Table 3.0-2 (page 3.0-3). As discussed in LRA Appendix C, Section 5.1 (page C-11), loss of material is not an applicable aging effect for copper alloy materials exposed to these environments. The applicant also stated that this conclusion is supported by a review of St. Lucie plant-specific operating experience, which did not identify loss of material as an aging effect requiring management for these components.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the plant-specific operating experience demonstrates that loss of material is not an applicable aging effect for copper alloy material exposed to the environment described in the RAI 3.3.11-2.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff’s evaluation of the applicant’s response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-4 pertaining to the chloride-related corrosion in the embedded/encased stainless steel piping/fitting. The staff’s evaluation of the applicant’s response is documented in Section 3.3.17.4 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s response to the above RAIs, the staff finds that the aging effects that result from contact of the primary makeup water system SSCs to the environments described in Section 2.3.3.11 and Table 3.3-11, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.11.2.2 Aging Management Programs

In Table 3.3-11, of the LRA, the applicant credited the following aging management programs for managing the aging effects in the components in the primary makeup water system:

- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-11, the staff concludes that the above-identified AMPs will effectively manage the aging effects of the primary makeup water system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11.3 Conclusion

The staff reviewed the information in Section 2.3.3.11 and Table 3.3-11 of the LRA, and the additional information included in the applicant’s response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the primary makeup water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the primary makeup water system as required by 10 CFR 54.21(d).

3.3.12 Sampling System

3.3.12.1 Summary of Technical Information in the Application

The sampling system provides the means to obtain samples from the RCS and auxiliary systems for chemical and radiological tests of boron concentration, fission and corrosion product levels, chloride, pH, and conductivity levels. A high pressure and high temperature sample from the hot leg of the RCS is routed to the sampling system where it is cooled to 120 ^{o}F or less and 25 psig in pressure in a sample heat exchanger. Samples are also obtained from the shutdown cooling system and the chemical and volume control system at a temperature of 120 ^{o}F and a pressure of approximately 25 psig. The sampling room is located in the reactor auxiliary room. The major components of the sampling system are constructed from stainless steel to minimize any potential corrosion problems. The major components of the sampling system include heat exchanger, sample vessel, sink and hood, and delay line. The sample delay line consists of 150 feet tubing to allow for the decay of radionuclides of the reactor coolant. Details of the sampling system are described in Unit1 UFASR Section 9.3.2 and Unit 2 UFAR Section 9.3.2.

3.3.12.1.1 Aging Effects

Components of the nuclear sampling system are described in Section 2.3.3.12 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-12, page 3.3-70 of the LRA lists individual components of the system including valves, tubing/fittings, and bolting. An internal environment of borated water causes the aging effect of loss of material and cracking in stainless steel components. Stainless steel components are identified as being subject to the external environments of indoor-not-air-conditioned and containment air and are subject to no aging effects. Carbon steel bolting is identified as being subject to the external environments of indoor-not-air-conditioned and containment air, and are subject to no aging effects. Carbon steel bolting is identified as being subject to the external environments of borated water with aging effects of loss of material and cracking identified.

3.3.12.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the sampling system:

- Chemistry Control Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the sampling system will be adequately managed by these AMPs for the period of extended operation.

3.3.12.2 Staff Evaluation

The applicant described its AMR of the sampling system for license renewal in Section 2.3.3.12 and Section 3.3, Table 3.3-12. The process of identification of the aging effects is summarized in Appendix C of the LRA, and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the sampling system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.12.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.12, Table 3.3-12, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the sampling system SSCs to the environments described in Section 2.3.3.12 and Table 3.3-12 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.12.2.2 Aging Management Programs

In Table 3.3-12, of the LRA, the applicant credited the following AMPs for managing the aging effects in the sampling system:

- Chemistry Control Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-12, the staff concludes that the above-identified AMPs will effectively manage the aging effects of the sampling system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12.3 Conclusion

The staff reviewed the information in Section 2.3.3.12 and Table 3.3-12 of the LRA, and the additional information included in the applicant’s response to the above RAI. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the sampling system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.4-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the sampling system as required by 10 CFR 54.21(d).

3.3.13 Service Water System

3.3.13.1 Summary of Technical Information in the Application

The service water system supports fire protection and supplies water to the plant shutdown stations, decontamination facilities, and portable water system. Details of the service water system are described in Unit 1 UFSAR Section 9.2.6 and Unit 2 UFSAR Section 9.2.4.

3.3.13.1.1 Aging Effects

Components of the service water system are described in Section 2.3.3.13 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-13, pages 3.3-70 through 3.3-71, of the LRA lists individual components of the system including yard sump pump, valves, piping/fittings, and bolting. Loss of material is identified as an aging effect for stainless steel components exposed to internal environment of raw water drains. No aging effect is identified for stainless steel components exposed to internal environment of raw water city water. Loss of material is identified as an aging effect for copper alloy and galvanized carbon steel components exposed to internal environment of air/gas (wetted). Loss of material is identified as an aging effect for stainless steel components exposed to external environment of raw water-drains. Loss of material and cracking are identified as aging effects for stainless steel components exposed to external environment of outdoor. No aging effect is identified for stainless steel, copper alloy, galvanized carbon steel, and carbon steel components exposed to external environment of outdoor and indoor-not-air-conditioned. Loss of mechanical closure integrity is identified for carbon steel bolting exposed to external environment of borated water leaks.

3.3.13.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the service water system:

- Periodic Surveillance and Preventive Maintenance Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the service water system will be adequately managed by these AMPs for the period of extended operation.

3.3.13.2 Staff Evaluation

The applicant described its AMR of the service water system for license renewal in Section 2.3.3.13 and Table 3.3-13. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA, to determine whether the applicant had demonstrated that the effects of aging on the service water system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.13.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.13, Table 3.3-13, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff's evaluation of the applicant's response is documented in Section 3.3.17.2 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the service water system SSCs to the environments described in Section 2.3.3.13 and Table 3.3-13, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.13.2.2 Aging Management Programs

In Table 3.3-13, of the LRA, the applicant credited the following AMPs for managing the aging effects in the service water system:

- Periodic Surveillance and Preventive Maintenance Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

During its review of the information in Section 2.3.3.13 and Table 3.3-13 of the LRA, the staff determined that additional information was needed to complete its review. In Table 3.3.13-1, the applicant credited the Periodic Surveillance and Preventive Maintenance Program for managing loss of material for the yard sump pump exposed to internal environment of raw water drains. In Appendix B of the LRA, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program provides visual inspection of component surfaces. By letter dated July 1, 2002, the staff requested, in RAI 3.3.13-1, the applicant to describe how visual inspection is conducted for the submerged surfaces of the sump pump.

In its response dated September 26, 2002, the applicant stated that the total sump depth for the pump subject to inspection is 2.5 feet. Dewatering of that sump will be performed, if necessary, to perform a visual inspection. On the basis of its review, the staff finds the applicant's response to RAI 3.3.13-1 acceptable because it clarifies how visual inspection is conducted for the submerged surface of the sump pump by the Periodic Surveillance and Preventive Maintenance Program, as requested by the staff.

Based on its review of LRA Table 3.3-13, and the information provided in the applicant's response to RAI 3.3.13-1, the staff concludes that the above-identified AMPs will effectively manage the aging effects of the service water system, so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13.3 Conclusion

The staff reviewed the information in Section 2.3.3.13 and Table 3.3-13 of the LRA, and the additional information included in the applicant’s response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the service water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.1-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the service water system as required by 10 CFR 54.21(d).

3.3.14 Turbine Cooling Water System (Unit 1 only)

3.3.14.1 Summary of Technical Information in the Application

Turbine cooling water system (Unit 1 only) is a closed-loop system used to remove heat from the turbine and other components in the power cycle, including the instrument air compressors. Details of turbine cooling water system are described in Unit 1 UFSAR Section 9.2.4.

3.3.14.1.1 Aging Effects

Components of the turbine cooling water system are described in Section 2.3.3.14 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-14, pages 3.3-73 through 3.3-74, of the LRA lists individual components of the system including stainless steel thermowells, carbon steel tanks, pumps, air fan cooler heads, valves (pressure boundary only), piping, fittings and bolting (mechanical closures), brass instrument air fan cooler tubes and instrument air fan cooler fins, and glass sight glasses. Stainless steel components are identified as subject to loss of material aging effects due to exposure to treated water. Exposure of stainless steel components to non-air-conditioned environment has no aging effects. Carbon steel components exposed to treated water and non-air-conditioned environment are subject to the aging effect of loss of material. Exposure of carbon steel components to air/gas environment has no aging effects. Exposure of carbon steel bolting components to non-air-conditioned environment has no aging effect. Brass components exposed to treated water and non-air-conditioned environments are subject to loss of material and fouling aging effects. Exposure of glass components to treated water and non-air-conditioned environments has no aging effects.

3.3.14.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the turbine cooling water system:

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the turbine cooling water system will be adequately managed by these AMPs for the period of extended operation.

3.3.14.2 Staff Evaluation

The applicant described its AMR for the turbine cooling water system for license renewal in Section 2.3.3.14 and Section 3.3, Table 3.3-14. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the turbine cooling water system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.14.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.14, Table 3.3-14, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

The component in the turbine cooling water system exposed internally to the air/gas environment is the instrument air compressor cooling water head tank (carbon steel). Instrument air upstream of the air dryers is annotated as "wetted." The applicant did not identify any aging effects for carbon steel instrument air compressor cooling water head tank exposed to the internal air/gas environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.14-1, the applicant identify the composition of the internal air/gas environment to which the Unit 1 instrument air compressor cooling water head tank is exposed, and specify the level of humidity of this particular environment. The applicant was also requested to clarify whether the tank wall is subjected to a changing wetting environment as the water level changes. In addition, the staff requested the applicant discuss whether loss of material is an applicable aging effect for this component.

In its response dated September 26, 2002, the applicant stated that the instrument air cooling water head tank is a small diameter tank with a hinged access cover in its top. This tank is normally filled with turbine cooling water to a level approximately 1" from the top of the tank. Turbine cooling water is chemically controlled and is treated with a corrosion inhibitor. The tank is vented and, therefore, the small air space above the normal water level of the tank is exposed to atmospheric conditions. The tank is internally coated to protect the carbon steel surface from general corrosion. A visual inspection of the tank performed as part of the aging management review did not identify any significant coating degradation or signs of general corrosion. Additionally, even if loss of material due to general corrosion were to occur in this portion of the tank, it would not impact the component or system intended function. Therefore, there are no aging effects requiring management for the internal surfaces of this tank exposed to an air/gas environment.

On the basis of its review, the staff finds that the applicant’s response to RAI 3.3.14-1 is reasonable and adequate because the applicant has provided the detailed information on the tank and its environment, as well as the results of the inspection performed as part of the aging management review that did not identify any significant coating degradation or signs of general corrosion.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not air conditioned, and containment air environments. The staff’s evaluation of the applicant’s response is documented in Section 3.3.17.1 of the SER and is characterized as resolved.

By letter dated July 1, 2002, the staff issued RAI 3.3-2 pertaining to potential boric acid corrosion in components that might be externally exposed to borated coolant leaking from an adjacent system or component containing borated coolant. The staff’s evaluation of the applicant’s response is documented in Section 3.3.17.2 of the SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant’s response to the above RAIs, the staff finds that the aging effects that result from contact of the turbine cooling water system SSCs to the environments described in Section 2.3.3.14 and Table 3.3-14, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.14.2.2 Aging Management Programs

In Table 3.3-14 of the LRA, the applicant credited the following AMPs for managing the aging effects for the components in the turbine cooling water system:

- Chemistry Control Program
- Galvanic Corrosion and Susceptibility Program
- Systems and Structures Monitoring Program

These AMPs are also credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-14, the staff concludes that these AMPs will effectively manage the aging effects of the turbine cooling water system and there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.14.3 Conclusion

The staff reviewed the information in Section 2.3.3.14 and Table 3.3-14 of the LRA, and the additional information included in the applicant’s response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the turbine cooling water system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.1-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the service water system as required by 10 CFR 54.21(d).

3.3.15 Ventilation

3.3.15.1 Summary of Technical Information in the Application

Ventilation provides heating, ventilation, and air conditioning to various buildings and rooms/areas throughout the plant. Ventilation includes the following eight subsystems control room air conditioning, emergency core cooling system area ventilation, fuel handling building ventilation (Unit 2 only), intake structure ventilation (Unit 2 only), miscellaneous ventilation (Unit 1 only), reactor auxiliary building electrical and battery room ventilation, reactor auxiliary building main supply and exhaust, and shield building ventilation. Details of the ventilation system are described in Unit 1 UFSAR Sections 6.2 and 9.4, and Unit 2 UFSAR Sections 6.2 and 9.4.

3.3.15.1.1 Aging Effects

Components of the ventilation system are described in Section 2.3.3.15 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-15, pages 3.3-75 through 3.3-88 of the LRA, lists individual components of the system including valves (pressure boundary only), filter housings, heat exchangers, flexible connections, ducts, demisters, thermowells, orifices, structural supports, piping, tubing, and fittings. The copper-nickel heat exchanger components and carbon steel piping/fittings and valves (Unit 2 only) of the control room air conditioner are internally exposed to treated water. The corresponding aging effects requiring management are loss of material and fouling. The stainless steel piping/fittings (Unit 2 only) of the control room air conditioner are internally exposed to treated water. Their corresponding aging effect requiring management is loss of material. The carbon steel components of the ventilation system are internally exposed to air/gas environment (atmospheric air or outside air with uncontrolled humidity and temperature). The corresponding aging effect requiring management is loss of material. The carbon steel components of the ventilation system are externally exposed to indoor-not air-conditioned environment or borated water leaks. The corresponding aging effect requiring management is loss of material. The galvanized carbon steel components of the reactor auxiliary building electrical and battery room ventilation system are internally exposed to outside air with uncontrolled humidity and temperature (one type of air/gas environment). The corresponding aging effect requiring management is loss of material. The galvanized carbon steel ducts in the ventilation system are externally exposed to borated water leaks. The corresponding aging effect requiring management is loss of material. The flexible connections made of rubber-coated cloth are internally exposed to air/gas environment and externally exposed to indoor-not-air-conditioned environment. The corresponding aging effect requiring management is cracking. The carbon steel bolting (mechanical closure) is externally exposed to borated water leaks. The corresponding aging effects requiring management is loss of mechanical integrity and loss of material.

3.3.15.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the ventilation system:

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the ventilation system will be adequately managed by these AMPs for the period of extended operation.

3.3.15.2 Staff Evaluation

The applicant describes its AMR of the eight subsystems of the ventilation system for license renewal in Section 2.3.3.15 and Section 3.3, Table 3.3-15. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ventilation system will be adequately managed for the extended operation as required by 10 CFR 54.21(a)(3).

3.3.15.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.15, Table 3.3-15, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

For control room air conditioning subsystem, the applicant has identified loss of material as an applicable aging effect for carbon steel filter housing internally exposed to air/gas environment, but not for other carbon steel components (e.g., valves and piping/fittings) exposed to the same environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.15-1, the applicant to explain this discrepancy. In its response dated November 27, 2002, the applicant provided the following information. The carbon steel valves and piping/fittings identified in LRA Table 3.3-15 exposed to an air/gas environment are associated with Unit 1 control room air conditioning outside air intake system. The internal air/gas environment for the piping and valves is outside air. As discussed in LRA Appendix C, Section 5.1 (page C-11), carbon steel is considered susceptible to loss of material due to general corrosion in this environment. As such, the aging management review of these components evaluated the potential impact of this aging effect on component intended function.

Unlike the carbon steel ventilation housings, which are constructed of heavy gage sheet metal, the carbon steel piping evaluated here is Schedule 40 and has a nominal thickness of 0.280 inches. The valves, which are wafer-type butterfly valves, have a body thickness greater than 1 inch. The applicant used the conservative corrosion rates for steel exposed to "inland environment" from Tables 6-1 and F-1 of MCIC Report, July 1986, "Corrosion of Metals in Marine Environment" by J. A. Beavers, G. H. Koch and W. E. Berry, and calculated the worst case average loss of wall thickness of 76 mils (3 mils/yr x 8 yrs + 1 mil/yr x 52 yrs) over the life of the plant. The applicant stated that the average reduction in thickness is estimated because the aging mechanism of concern for the internal surfaces of the control room air conditioning outside intake valves/piping/fittings is general corrosion. The applicant further stated that due to the location of these components and their limited air exchange with the environment, aggressive chemical species will not be present and significant pitting corrosion is not expected. The applicant stated that the inland environment data is applicable based upon expected conditions for the air space inside the control room air conditioning intake components. The control room air conditioning outside intake line is located inside the reactor auxiliary building and is normally isolated. Thus, high humidity of inland tropical environment without aggressive species, such as chlorides, is applicable.

The applicant further stated that the corrosion rate decreases with time due to the buildup of an oxidation layer, which will tend to provide some protection of the bare metal underneath. Thus, based upon this worst-case corrosion rate, the remaining piping wall thickness is 0.204 inches. Since this portion of the ventilation system is non-pressurized, the remaining wall thickness must only address structural loads, and it is concluded that adequate corrosion allowance exists for these components. Therefore, loss of material due to corrosion of the internal surfaces of valves, piping, and fittings associated with the control room air conditioning outside air intake (which are exposed to an air/gas environment) is not an aging effect requiring management.

On the basis of its review, the staff finds the applicant's conclusion that loss of material due to corrosion is not an aging effect for these components that requires management acceptable because the applicant demonstrated that these components have sufficient corrosion allowance.

By letter dated July 1, 2002, the staff issued RAI 3.3-1 pertaining to potential aging effects of closure bolting exposed externally to outdoor, indoor-not-air-conditioned, and containment air environments. The staff's evaluation of the applicant's response is documented in Section 3.3.17.1 of this SER and is characterized as resolved.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the ventilation system SSCs to the environments described in Section 2.3.3.15 and Table 3.3-15, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.15.2.2 Aging Management Programs

In Table 3.3-15, of the LRA, the applicant credited the following AMPs for managing the aging effects in the ventilation system:

- Chemistry Control Program
- Galvanic Corrosion Susceptibility Inspection Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

The description of the Periodic Surveillance and Preventive Maintenance Program is provided in Section 3.2.11, Periodic Surveillance and Preventive Maintenance Program, of Appendix B to the LRA. The staff's detailed evaluation of this program is presented in Section 3.0.5.9 of this SER. The periodic surveillance and preventive maintenance program provides for visual inspection, examination of component surfaces, and leakage inspections to determine the existence of internal corrosion or cracking. Therefore, it appears that the applicant relies on detection of leakage for managing loss of material on the inside surface of several components exposed to air/gas environment. The presence of leakage from a component, however, would indicate that the component has lost its ability to perform its intended function, i.e., pressure boundary integrity. By letter dated July 1, 2002, the staff requested, in RAI 3.3.15-2, the applicant explain how the component's capability to perform its intended function is maintained. In its response dated September 26, 2002, the applicant stated that loss of material in the ventilation system carbon steel components is managed by visual inspections and examinations of the plenums, housings, shells, and supports. The applicant further stated that leak inspection is not credited for aging management of the ventilation systems listed in LRA Table 3.3-15.

On the basis of its review, the staff finds the applicant's response to RAI 3.3.15-2 acceptable because the applicant demonstrated that pressure boundary integrity of the ventilation system components, which are internally exposed to air/gas environment, is maintained by visual inspections and examinations of the Periodic Surveillance and Preventive Maintenance Program.

Based on its review of LRA Table 3.3-15, with the exception of open item 3.0.2.2-1, the staff concludes that the above-identified AMPs will effectively manage the aging effects of the ventilation system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15.3 Conclusion

The staff reviewed the information in Section 2.3.3.15 and Table 3.3-15 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the ventilation systems will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory item 3.0.2.2-1 and 3.0.5.1-1, the staff also concluded that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the ventilation systems as required by 10 CFR 54.21(d).

3.3.16 Waste Management

3.3.16.1 Summary of Technical Information in the Application

The waste management collects, monitors, and processes potentially radioactive reactor plant wastes prior to release or removal from the plant site. The waste management system consists of three subsystems liquid, gaseous, and solid waste management. Liquid wastes include those from the laboratory sink drains, decontamination area drains, floor drains, building sumps, and contaminated showers. The solid waste management system collects, controls, processes, packages, handles, and temporarily stores solid radioactive waste. The solid waste management system consists of spent resin tank, piping, and valves connecting to a shipping container and to the ECCS sump for resin drain/dewatering operations. Details of the waste management system are described in Unit 1 UFSAR Sections 9.3.3, 11.2.2, 11.3.2, and 11.5.2, and Unit 2 UFSAR, Sections 9.3.3, 11.2.2, 11.3.2, and 11.4.2.

3.3.16.1.1 Aging Effects

Components of the waste management system are described in Section 2.3.3.16 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-16, pages 3.3-89 through 3.3-91 of the LRA, lists individual components of the system including valves, piping/fittings, cleanout plugs, strainers, orifices, and bolting.

The components in the waste management system are fabricated from nickel alloy, carbon steel, bronze, stainless steel, and copper alloy, and are exposed to internal environment of air/gas. These components include valves, piping/fitting, cleanout plugs, strainers, strainer element, and orifices. Loss of material is identified as an applicable aging effect for the carbon steel cleanout plugs exposed to the internal environment of air/gas. The applicant stated that the internal air/gas environment in the cleanout plugs is outside air with uncontrolled humidity and temperature. No aging effect is identified for the nickel alloy, carbon steel, bronze, stainless steel, and copper alloy components exposed to internal air/gas environment of inside air with controlled humidity and temperatures. No aging effect is identified for the stainless steel components exposed to internal environment of raw water (drains) or air/gas. The raw water (drains) is the fluids collected in building drains. The fluids can be treated water (primary, secondary, borated, or other), raw water (cooling canals or city water), fuel oil, or lubricating oil.

Loss of material is identified for the carbon steel components exposed to external environments of indoor (not-air-conditioned) or containment air. The external indoor (not air-conditioned) environment is atmospheric air, a temperature of 104 ^oF maximum, 73 percent average humidity, and no exposure to weather. The external containment air environment is atmospheric air, a temperature of 120 ^oF maximum, 73 percent average humidity, and no exposure to weather. Loss of material and loss of mechanical closure integrity are identified as the applicable aging effects for carbon steel components exposed to external environment of borated water leaks. No aging effect is identified for the stainless steel, nickel alloy, bronze, and copper alloy components exposed to external environments of indoor (not air-conditioned) or containment air. No aging effect is identified for the stainless steel components exposed to external environment of embedded/encased in concrete.

3.3.16.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects in the waste management system:

- System and Structure Monitoring Program
- Boric Acid Wastage Surveillance Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the waste management system will be adequately managed by these AMPs for the period of extended operation.

3.3.16.2 Staff Evaluation

The applicant described its AMR of the waste management system for license renewal in Section 2.3.3.16 and Section 3.3, Table 3.3-16. The process of identification of the aging effects is summarized in Appendix C of the LRA and a description of the AMPs is provided in Appendix B of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the waste management system will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.16.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.16, Table 3.3-16, and the applicable sections in Appendix C of the LRA. During its review, the staff determined that additional information was needed to complete its review.

In Table 3.3-13 of the LRA, the applicant identifies loss of material as an applicable aging effect for the stainless steel yard sump pump of the service water system which is exposed to an internal environment of raw water (drains), but not for the stainless steel valves and piping/fittings exposed to the same environment. By letter dated July 1, 2002, the staff requested, in RAI 3.3.16-1, the applicant explain why loss of material is not identified as an applicable aging effect for the stainless steel valves and piping/fittings of the waste management system, which are exposed to the same environment of raw water (drains).

In its response dated September 26, 2002, the applicant stated that the stainless steel yard sump is located in the pipe trench connected to the Unit 2 CCW structure, and thus is exposed to raw water consisting of drainage run-off. This water may be high in chlorides or other contaminants and therefore may create an aggressive environment for corrosion. On the other hand, the subject portion of the waste management system drains consists of that portion of the system from the reactor coolant drain tank outlet which penetrates containment. These drains are from in- containment sources such as RCS loop drains and other inputs to the reactor coolant drain tank. A review of St. Lucie plant-specific operating experience of waste management did not identify any instances of loss of material for this system. In addition, a volumetric inspection performed as part of the aging management review for stainless steel waste management piping in the reactor auxiliary buildings identified no loss of material for these portions of the system. Therefore, loss of material is not an aging effect requiring management for the stainless steel valves and piping/fittings of waste management exposed to the environment of raw water (drains).

On the basis of its review, the staff finds that the applicant's response to RAI 3.3.16-1 clarifies and satisfactorily resolves the item because the applicant demonstrated that environment of raw water (drains) in the waste management system is less aggressive and loss of material is not an applicable aging effect which is validated by the plant operating experience.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the waste management system SSCs to the environments described in Section 2.3.3.16 and Table 3.3-16, are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.16.2.2 Aging Management Programs

In Table 3.3-16, pages of the LRA, the applicant credited the following AMPs for managing the aging effects in the waste management system:

- Systems and Structures Monitoring Program
- Boric Acid Wastage Surveillance Program

These AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0.5 of this SER.

Based on its review of LRA Table 3.3-16, the staff concludes that the AMPs identified above will effectively manage the aging effects of the waste management system so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16.3 Conclusion

The staff reviewed the information in Section 2.3.3.16 and Table 3.3-16 of the LRA, and the additional information included in the applicant's response to the above RAIs. On the basis of its review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the waste management system will be adequately managed so that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1 and 3.0.5.4-1, the staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the waste management system as required by 10 CFR 54.21(d).

3.3.17 General AMR Issues

This section discusses the staff's evaluation on seven general AMR issues that are applicable to components in several auxiliary systems included in Section 3.3 of the LRA.

3.3.17.1 Aging Effects for Closure Bolting

The applicant did not identify loss of material and cracking for some closure boltings in several auxiliary systems included in Section 3.3 of the LRA. Since closure bolting may be exposed to warm air, moisture, and leaking fluid (boric acid) environments, it may be subject to the aging effects of loss of material and cracking. By letter dated July 1, 2002, the staff requested, in RAI 3.3-1, the applicant justify why the LRA excludes the aging effects, including loss of material and cracking, for carbon steel, stainless steel, bronze, brass, and copper boltings in the following systems and for the environments to which they are exposed. The environments include outdoor, indoor-not-air-conditioned, containment, and buried environments. The systems that should be considered are instrument air, component cooling water, diesel generator, intake cooling water, primary water makeup, service water system, turbine cooling water (Unit 1 only), ventilation, sampling, and steam and power conversion. The staff also requested the applicant provide a summary of the plant-specific operating experience associated with the degradation of bolting.

In its response dated September 26, 2002, the applicant stated that as discussed in LRA Appendix C, Subsection 5.4 (page C-16), "Loss of Mechanical Closure Integrity", the loss of bolting material and cracking were evaluated for their effects on mechanical closure integrity. Only loss of bolting material associated with aggressive chemical attack (e.g., borated water leaks) was determined to require aging management. The closure boltings in instrument air, CCW, ICW, primary water, service water, ventilation, and steam and power conversion systems credit the Boric Acid Wastage Surveillance Program for managing loss of mechanical closure integrity due to boric acid corrosion. The emergency diesel generators and turbine cooling water are not subject to loss of material due to boric acid corrosion based upon the distance of those systems to borated water sources.

The applicant further stated that although the LRA identifies bolting (mechanical closures) material as carbon steel, the actual bolting material for St. Lucie piping and components is a low alloy steel ASTM A193, Grade B7. This material provides increased corrosion resistance over carbon steel. Additionally, bolting is typically in a dry (non-wetted) environment and is coated with a lubricant. At St. Lucie, it is a standard maintenance practice to clean and lubricate bolting prior to assembly of components. The applicant also stated that lubrication of bolting is addressed in general maintenance bolting procedures. When the bolting is associated with a system that operates at a temperature greater than 212 ^{o}F (such as main steam, auxiliary steam, main feedwater, and steam generator blowdown) or is located in an air-conditioned environment (such as some ventilation system components), it further eliminates the presence of moisture and potential for corrosion. Although bolting located in outdoor, indoor-not-air-conditioned, and containment environments is subject to an average humidity level of 73 percent (as described in LRA Appendix C, Section 4.2, page C-9), a review of St. Lucie plant-specific operating experience only identified a few cases of corrosion of bolting. These cases were associated with nonpressure boundary valve gland bolting with the corrosion attributed to packing leaks. It is the plant policy to minimize operation with valve packing leaks, and thus, packing leaks are identified and repaired on a timely basis. As such, loss of material due to general or pitting corrosion is not an applicable aging effect for low-alloy steel bolting. The applicant also stated that pitting of stainless steel bolting material has not been experienced at St. Lucie.

The applicant further stated that as indicated in LRA Appendix C, Section 1.0 (page C-3), FPL utilized the industry guidance developed by the Babcock and Wilcox Owners Group in determining the aging effects requiring management. As part of the development of this Industry guidance document, a review of industry data (including other saltwater nuclear plant sites) was performed. Industry data reviewed included Nuclear Plant Reliability Data System and NRC generic publications. The results of this review of industry operating experience did not identify loss of material due to general corrosion or pitting as an aging effect requiring management for bolting. Therefore, the applicant concluded that apart from aggressive chemical attack, loss of bolting material due to corrosion is not an applicable aging effect for the systems identified in RAI 3.3-1.

In addition, the applicant stated that as discussed in LRA Appendix C, Subsection 5.4 (page C-16), the potential for stress corrosion cracking (SCC) of bolting materials has been addressed at St. Lucie as part of corrective actions to NRC IE Bulletin 82-02. These actions have been effective in eliminating this aging effect. A review of St. Lucie plant-specific operating experience identified no instances of bolting degradation due to SCC. Additionally, a review of NRC generic communications did not identify any recent bolting failures attributed to SCC. Therefore, the applicant concluded that cracking of bolting material due to SCC is not an aging effect requiring management for the systems identified in RAI 3.3-1. The applicant further noted that this position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the information provided by the applicant included the distance of the systems to borated water sources and identified the type of material used for manufacturing the bolts as low alloy steel ASTM A193, Grade B7. In addition, the industry and St. Lucie plant-specific operating experience demonstrated that loss of material and cracking are not the applicable aging effects for closure bolting.

3.3.17.2 Boric Acid Corrosion

By letter dated July 1, 2002, the staff requested, in RAI 3.3-2, the applicant clarify whether the following components are likely to be externally exposed to borated coolant leaking any adjacent systems or components:

- CCW system carbon steel surge tanks, pump bodies, and heat exchanger shells

- demineralized makeup water system (any component)
- instrument air system carbon and galvanized steel components, such as instrument air receivers, bolting, dryers, and compressor cooler shells
- ICW system carbon steel basket strainers and valve bodies
- turbine cooling water (Unit 1 only) system carbon steel components

In its response dated September 26, 2002, the applicant stated that the following components are not in proximity to any systems which contain borated water and therefore are not exposed to borated water leaking from any adjacent systems or components:

- CCW carbon steel surge tanks, pump bodies, and heat exchanger shells
- instrument air receivers, bolting, dryers, and compressor cooler shells and associated components
- ICW carbon steel basket strainers and valve bodies
- turbine cooling water carbon steel components

Some instrument air components may be exposed to borated water leakage from adjacent systems or components LRA Table 3.3-8, pages 3.3-56, 3.3.-57, and 3.3.-58.

Loss of material due to boric acid corrosion of instrument air carbon steel components exposed to borated water leaks is managed by the Boric Acid Wastage Surveillance Program.

The applicant further stated that demineralized makeup water components are stainless steel and thus not susceptible to boric acid wastage. The demineralized makeup water bolting in the scope of license renewal is not in proximity to any systems that contain borated water and therefore cannot be exposed to borated water leaking from any adjacent systems or components.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because the information provided by the applicant clarifies that these components are not exposed to boric acid leaking and, therefore, boric acid corrosion is not an applicable aging effect.

3.3.17.3 Chloride-Related Corrosion in Embedded/Encased Carbon Steel Piping/Fitting

The outdoor environment of St. Lucie is defined in the LRA as moist, salt-laden atmospheric air, with temperatures of 27 ^{o}F - 93 ^{o}F, 73 percent average humidity, and exposure to weather, including precipitation and wind. The outdoor environment also contains chlorides. These chlorides in the moist, salt-laden atmospheric air may reach the steel/concrete interface in the interior of the concrete through the process of permeation, infiltration, and condensation through the pores of the concrete. Accumulation of high enough levels of chlorides will result in attacks on and disruption of the protective film formed on the surfaces of the steel as a result of the originally high pH levels in the concrete environment. Once some particular region of the protective film is destroyed, localized corrosion of the steel will begin through an electrochemical process. However, the applicant did not identify any aging effects for carbon steel components in the emergency cooling canal system and the ICW system exposed to an embedded/encased environment.

By letter dated July 1, 2002, the staff requested, in RAI 3.3-3, the applicant clarify the environment to which the concrete with embedded/encased carbon steel piping/fitting is exposed. The applicant was also requested to explain why the above-described aging process is not applicable to St. Lucie, and to discuss the plant operating history concerning carbon steel components exposed to an embedded/encased environment, to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that the emergency cooling canal embedded/encased piping listed on LRA Table 3.3-5 is actually bolted to the concrete and is therefore not embedded/encased. In addition, the piping/fitting and bolting shown on LRA Table 3.3-5 are made of aluminum bronze and not carbon steel. LRA Table 3.3-5 (page 3.3-41) is revised. For the aluminum bronze piping/fittings and bolting exposed to raw water - salt water (submerged) environment, the applicable aging effect is loss of material and the Periodic Surveillance and Preventive Maintenance Program is credited for managing this aging effect.

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

On the basis of its review, the staff finds the applicant's response to RAI 3.3-3 concerning the components in emergency cooling canal system reasonable and adequate because the applicant identified the aging effect of loss of materials for the components in this system and credited the Periodic Surveillance and Preventive Maintenance Program for managing this aging effect. The staff also finds the applicant's response to the RAI concerning the ICW reasonable and adequate because plant-specific operating experience did not identify chloride-related corrosion as an aging effect for this piping system.

3.3.17.4 Chloride-Related Corrosion in Embedded/Encased Stainless Steel Piping/Fitting

In Table 3.3-11, "Primary Makeup Water," of the LRA, the applicant stated that no aging effect requiring aging management is applicable to stainless steel piping/fittings embedded/encased in concrete. Stainless steel components are much more resistant to chloride-related corrosion than carbon steel components. However, the applicant also stated that plant experience has identified loss of materials and cracking as applicable aging effects for stainless steel components in the emergency core cooling system (ECCS) pipe tunnel.

By letter dated July 1, 2002, the staff requested, in RAI 3.3-4, the applicant to explain why the aging effects applicable to stainless steel components in the ECCS pipe tunnel are not applicable to the stainless steel piping/fittings embedded/encased in concrete at St. Lucie. The applicant was also requested to discuss the operating history concerning stainless steel components in the embedded/encased environment to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that as indicated in the response to RAI 3.3.1-2, stainless steel components located in the ECCS tunnels at St. Lucie have greater susceptibility to corrosion (i.e., pitting and stress corrosion cracking) due to their potential for increased external chloride contamination. The applicant stated that the terms "tunnels" and "trenches" are synonymous at St. Lucie. This greater potential for external contamination applies to the components whose surfaces are exposed to the air environment in the tunnel, not to those which are embedded/encased in concrete. The high alkalinity of concrete provides an environment that protects the stainless steel from corrosion. The applicant also stated that its review of the St. Lucie plant-specific operating experience did not identify any intrusion of chlorides into concrete in a non-wetted (i.e., not submerged) environment resulting in degradation of embedded/encased stainless steel.

In addition, the applicant stated that primary water piping/fitting identified in LRA Table 3.3-11 (page 3.3-68) as exposed to an external environment of embedded/encased, are associated with piping which penetrates concrete that is not wetted. Therefore, there is no potential for chloride intrusion into the concrete. As a result, the applicant concluded that loss of material and cracking are not aging effects requiring management for primary water components exposed to an embedded/encased environment.

On the basis of its review, the staff finds that the applicant's response is reasonable and adequate because the plant-specific operating experience did not identify any intrusion of chlorides into concrete in a non-wetted (i.e., not submerged) environment. In addition, there is a greater potential for external contamination to components whose surfaces are exposed to the air environment in the tunnel then there is to those components that are embedded/encased in concrete.

3.3.17.5 Corrosion Due to Carbonation in Embedded/Encased Carbon Steel Piping/Fitting

Even though the concrete structure in which the carbon steel components are embedded is only exposed to atmospheric air with negligible levels of chlorides, the embedded/encased steel piping/fittings may still be susceptible to a corrosion process attributable to the carbon dioxide present in the atmospheric air. This corrosion process operates via the generation of carbonic acid, which reduces the pH level in the vicinity of the steel/concrete interface. This neutralization process, in turn, disrupts the passivity of the protective films and permits attacks on the underlying carbon steel substrate. The water/cement ratio of the concrete is an important factor in affecting the rate of this corrosion process. By letter dated July 1, 2002, the staff requested, in RAI 3.3-5, the applicant to justify why this aging process is not applicable to St. Lucie, and to discuss the operating history to support its conclusion on excluding cracking and loss of materials as the applicable aging effects for these components.

In its response dated September 26, 2002, the applicant stated that the corrosion process discussed in this RAI is carbonation. According to the Portland Cement Association, the depth of carbonation of good quality, well-cured concrete is generally of little significance. As discussed in LRA sections 3.5.1.3 and 3.5.2.3 (pages 3.5-9 and 3.5-24 respectively), St. Lucie structures are made from high quality concrete materials (high strength, high cement content, low water-cement ratio, and controlled curing). In addition the operating experience at St. Lucie has not identified cracking or loss of material in steel piping/fitting embedded in concrete.

Therefore, the applicant concluded that carbonation is not a mechanism that causes aging effects requiring management at St. Lucie.

On the basis of its review, the staff finds the applicant's response reasonable and adequate because of the high quality concrete materials used by the applicant and the operating experience, which demonstrates that carbonation is not an aging mechanism that causes aging effects requiring management for embedded/encased carbon steel piping/fitting at St. Lucie.

3.3.17.6 Thermal Fatigue

In Section 3.3 of the LRA, the applicant did not identify cracking due to thermal fatigue as an aging effect requiring management for the auxiliary system components. Instead, the applicant identified thermal fatigue for piping systems designed to the requirements of ASME Section III, Class 2 and 3, and ANSI B31.1 as a time-limited aging analysis (TLAA) in Section 4.3.3.2 of the LRA. The staff's evaluation of this TLAA is provided in Section 4.3 of this SER. Therefore, the aging effect due to thermal fatigue, as it applies to auxiliary system components, will not be discussed further in this section of the SER.

3.3.17.7 Aging Management Review for Additional Components Within Auxiliary Systems

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii). By letter dated July 1, 2002, the staff requested, in RAI 2.1-1, the applicant to provide additional information relating to its evaluation of non-safety-related SSCs within the scope of license renewal.

In its response dated September 26, 2002, the applicant brought additional non-safety-related SSCs into the scope of license renewal. The staff's evaluation of the applicant's scoping and screening methodology for identifying those piping systems and components is described in Section 2.1.3 of this SER, and will not be discussed further in this section of the SER. The staff's evaluation of these additional non-safety-related components resulting from the applicant's scoping and screening process are discussed in Section 2.3.3 of this SER.

The applicant's response to the RAI also provides information regarding the management of aging effects associated with those additional non-safety-related SSCs that are brought into the scope of license renewal. The staff's evaluation of the information pertaining to the management of aging effects associated with the components within the auxiliary systems follows.

Table 2.1-1 of the applicant's RAI response lists additional auxiliary systems componets in the emergency diesel generator building including piping/fittings and valves. Table 2.1-2 lists additional auxiliary systems components in the reactor auxiliary buildings including piping/fittings, valves, and bolting (mechanical closures). The staff reviewed the information pertaining to component/ commodity group, material, environment, aging effects requiring management, and program/ activities. On the basis of its review, the staff finds that the aging effects identified for these additional components are consistent with those identified for other auxiliary systems components with the same combination of material and environment included in Section 3.3 of the LRA. In addition, the staff finds that the AMPs credited for managing these aging effects are the Chemistry Control Program and the Systems and Structures Monitoring Program. These two AMPs are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects as identified. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Therefore, the staff concludes that the applicant's response to RAI 2.1-1 is acceptable because the applicant has demonstrated that the aging effects associated with these additional non-safety-related auxiliary systems components will be appropriately managed for the period of the extended operation.

By letter dated July 18, 2002, the staff requested, in RAIs 2.3.3-13, 2.3.3-15, and 2.3.3.15-1, the applicant justify why some SSCs listed in UFSAR are not included within the scope of license renewal. In its responses, dated October 3 and November 27, 2002, the applicant brought additional components into the scope of license renewal for turbine cooling water system (Unit 1 only), fire protection system, and ventilation systems. Tables 3.3-14, 3.3-6, and 2.3.3-15-1-1 through -7 of the RAI response lists these additional components. The staff reviewed the information pertaining to component/commodity group, material, environment, aging effects requiring management, and program/activities. On the basis of its review, the staff finds that the aging effects identified for these additional components are consistent with those identified for other auxiliary systems' components with the same combination of material and environment included in Section 3.3 of the LRA.

In addition, the staff finds that the AMPs credited for managing these aging effects are Chemistry Control Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Fire Protection Program. To manage aging effect of loss of material in most of the ventilation system carbon steel components internally exposed to air/gas environment (atmospheric air or outside air with uncontrolled humidity and temperature), the applicant relies on the Periodic Surveillance and Preventive Maintenance Program. But in response to RAI 2.3.3.15-1, the applicant has committed to the use of the Systems and Structures Monitoring Program for managing loss of material in shield building ventilation system carbon steel damper housing, internally exposed to air/gas environment. However, the Systems and Structures Monitoring Program is typically utilized for managing external, and not internal, aging effects since it employs periodic visual inspections of external surfaces for evidence of degradation. The applicant provided the following justification for crediting the Systems and Structures Monitoring Program for managing loss of material at the inside surface of the shield building ventilation system damper housings. The ventilation dampers are located in indoor areas and their housings are internally coated, therefore, significant corrosion is not expected. Twenty-six years of operating experience has not identified that internal loss of material due to general corrosion has been a problem with these damper housings. The applicant further stated that any degradation of the internal coating with age could result in localized corrosion. If the corrosion was significant enough, the localized loss of material could result in a small perforation. This internal degradation would be evident by visible rust discoloration on the external surface of the damper housing. The applicant also stated that should internal coating degradation and corrosion lead to small perforations, this condition would be well within ventilation system capacity and would not impact intended function. In addition, shield building ventilation is periodically tested to verify system capability. The staff finds this response acceptable because the visual inspections of the external surface of the damper housing performed as part of the Systems and Structures Monitoring Program would detect rust discoloration resulting from the significant corrosion on the inside surface while maintaining the intended function of the shield building ventilation system.

Furthermore, the Chemistry Control Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Fire Protection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects as identified. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Therefore, the staff concludes that the applicant's responses to RAIs 2.3.3-13, 2.3.3-15, and 2.3.3.15-1 are acceptable because the applicant has demonstrated that the aging effects associated with these additional auxiliary systems components will be appropriately managed for the period of the extended operation.

3.4 Steam and Power Conversion Systems

In Section 3.4, "Steam and Power Conversion Systems," of the LRA, the applicant describes the AMR for the steam and power conversion systems (SPCS). Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the SPCSs. The staff reviewed Section 3.2 and the applicable portions of Appendices A, B, and C to determine whether the applicant provided sufficient information to demonstrate that the effects of aging will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis (CLB) throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3) for the SPCS' structures and components that are determined to be within the scope of license renewal and subject to an AMR.

The SPCSs include the following:

- main steam, auxiliary steam, and turbine system
- main feedwater and steam generator blowdown system
- auxiliary feedwater and condensate system

In Section 2.3.4 of the LRA, the applicant provides a description of these systems and identifies the components requiring an AMR for license renewal. The staff's evaluation of the scoping methodology and the SPCS' structures and components included within the scope of license renewal and subject to an AMR is documented in Sections 2.1 and 2.3.4, respectively, of this SER. In LRA, Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). In LRA, Appendix B, the applicant provides a more detailed description of these AMPs for the staff to use in its evaluation. In LRA, Appendix C, the applicant describes the process used to identify many of the applicable aging effects for the SCs that are subject to an AMR. In LRA, Appendix D, the applicant states that no changes to the St. Lucie Technical Specifications have been identified.

3.4.0 System-Specific Aging Management Programs

The Condensate Storage Tank Cross-Connect Buried Piping Inspection (Unit 1 only) AMP is specific to the steam and power conversion systems. The staff's evaluation of this AMP is provided below.

3.4.0.1 Condensate Storage Tank Cross-Connect Buried Piping Inspection (Unit 1 only)

The Condensate Storage Tank Cross-Connect Buried Piping Inspection Program is described in Section 3.1.1 of Appendix B to the LRA. The applicant credits this program for managing the external loss of material due to pitting and microbiologically influenced corrosion of components in the Unit 1 auxiliary feedwater and condensate system. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.0.1.1 Summary of Technical Information in the Application

The applicant credits the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program for aging management of the external surface of buried piping that cross-connects the condensate storage tanks. The condensate storage tanks are cross-connected between the units, but only the piping to the Unit 1 condensate storage tank is buried. This one-time inspection is plant specific. The GALL includes a similar program, Program XI.M28, "Buried Piping and Tanks Surveillance"; however, XI.M28 cannot be used for St. Lucie because XI.M28 is intended for carbon steel piping, whereas the St. Lucie condensate storage tank cross-connect pipe is stainless steel.

3.4.0.1.2 Staff Evaluation

The staff's evaluation of the Condensate Storage Tank Cross-Connect Buried Piping Inspection program focused on how the applicant demonstrates that the applicable aging effects of the structures and components that credit this program will be managed for the period of extended operation. The staff evaluated the program against the following 10 elements that are described in Appendix A to NUREG 1800—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: The scope of the program provides for inspection of a selected portion of the buried condensate storage tank cross-connect pipe. The scope is acceptable to the staff because it includes those components that rely on the program for aging management.

Preventive Actions: The applicant stated that no preventive actions are applicable to this inspection, and the staff concurs with this position.

Parameters Monitored or Inspected: The applicant stated that the inspection will assess the extent of external corrosion of the 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 (MIC). This is in accordance with general industry practice, and is acceptable to the staff.

Detection of Aging Effects: The applicant stated that the inspection provides for visual examination of the external surfaces of buried condensate storage tank cross-connect pipe to detect loss of material. The applicant also stated that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will use techniques with demonstrated capability and a proven industry record to assess external surface conditions of the buried portions of stainless steel. The examination will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been previously used to assess piping condition in many other plant systems. Because there is no operating history of degradation, a one-time inspection was selected. This is acceptable to the staff, since the degree of reduction of wall thickness due to pitting and MIC, as a result of loss of external surface material, is readily determinable by visual inspection.

Monitoring and Trending: The applicant stated that the one-time inspection will provide confirmatory information on the condition of the pipe. Visual inspection will detect degradation of the external surface of the pipe, and lead to thickness measurement if necessary. Because there is no operating history of degradation, a one-time inspection was selected. If significant loss of material is detected, the appropriate corrective action, including program revision if needed, will be implemented. This is acceptable, since piping thickness measurements will permit calculation of an outside diameter corrosion rate.

Acceptance Criteria: The applicant stated that the results of the examinations will be evaluated in accordance with the minimum wall thickness requirements of the applicable design code (ANSI B31.1). This will ensure that the integrity of the pipe is maintained, and is, therefore, acceptable.

Operating Experience: This is a one-time inspection, so there is no operating experience associated with this program. The applicant stated that there is no operating experience of degradation of this piping. The staff finds this reasonable and acceptable.

3.4.0.1.3 FSAR Supplement

The staff reviewed summary description of the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program in the FSAR supplements in Appendix A of the LRA. The staff finds that the information provided in the FSAR supplements for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities as required by 10 CFR 54.21(d).

3.4.0.1.4 Conclusion

The staff has reviewed the information provided in Section 3.1.1 of Appendix B of the LRA, and the summary description of the Condensate Storage Tank Cross-Connect Buried Piping Inspection program in Appendix A of the LRA. On the basis of this review and the above evaluation, the staff finds that the Condensate Storage Tank Cross-Connect Buried Piping Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.1 Summary of Technical Information in the Application

In Section 3.4 of the LRA, the applicant identifies three systems that require an AMR in accordance with 10 CFR 54.21(a)(3). The three systems are main steam—auxiliary and turbine, main feedwater and steam generator blowdown, and auxiliary feedwater and condensate. In Section 2.3.4 of the LRA, the applicant describes these systems.

Main steam, auxiliary steam, and turbine components subject to an AMR include valves (pressure boundary only), steam traps, strainers, thermowells, orifices, piping, tubing, and fittings. The intended functions for main steam, auxiliary steam, and turbine components subject to an aging management review are pressure boundary integrity, filtration, and throttling.

Main feedwater and steam generator blowdown components subject to an AMR include valves (pressure boundary only), accumulators, orifices, thermowells, piping, tubing, and fittings. The intended functions for the main feedwater and steam generator blowdown components subject to an AMR are pressure boundary integrity and throttling. A complete list of main feedwater and steam generator blowdown components that require an AMR and the component intended functions are shown in Table 3.4-2 of the LRA.

Auxiliary feedwater and condensate components subject to an AMR include tanks, pumps, turbines, and valves (pressure boundary only), coolers, orifices, vortex breakers, sightglasses, piping, tubing, and fittings. The intended functions for auxiliary feedwater and condensate components subject to an AMR are pressure boundary integrity, heat transfer, vortex prevention, and throttling. A complete list of auxiliary feedwater and condensate components that require an AMR and the component intended functions are provided in Table 3.4-3 of the LRA.

3.4.1.1 Aging Effects

In Table 3.4-1 through 3.4-3 of the LRA, the applicant describes the aging effects requiring management, and the programs and activities that manage the aging effects for each applicable environment and material combination. In Section 3.4 of the LRA, the applicant summarizes the following aging effects requiring management for each system.

Main Steam, Auxiliary Steam, and Turbines: The aging effects requiring management are loss of material for carbon steel, stainless steel, and nickel alloy components, and cracking for certain stainless steel and nickel alloy components. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue of main steam piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a TLAA and is addressed in section 4.3.2 of the LRA.

Main Feedwater and Steam Generator Blowdown: The aging effects requiring management are loss of material for carbon steel and stainless steel components, and cracking for certain stainless steel components. The aging effect requiring management for carbon steel mechanical closure bolting is loss of mechanical closure integrity. Fatigue of main feedwater piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a time-limited aging analysis and is addressed in Section 4.3.2 of the LRA.

Auxiliary Feedwater and Condensate: The aging effects requiring management are loss of material for carbon steel and stainless steel components. Fatigue of auxiliary feedwater piping and fittings is identified in the GALL Report as an aging effect. At St. Lucie, fatigue is a TLAA and is addressed in Section 4.3.2 of the LRA.

3.4.1.2 Aging Management Programs

In Section 3.4 of the LRA, the applicant identifies the following eight AMP that are utilized to manage the aging effects associated with the structures and components of the steam and power conversion systems:

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Condensate Storage Tank Cross-Connect Buried Pipe Inspection Program
- Pipe Wall Thinning Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concludes that the effects of aging associated with the structures and components of the SPCS will be adequately managed by these AMPs for the period of extended operations.

3.4.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Scoping and Screening Results," of this LRA, and the applicable AMP descriptions provided in Appendix B of the LRA, to determine whether the aging effects for the containment components have been properly identified and will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects, and the applicant's programs credited for the aging management of the SPCS components at St. Lucie. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the SPCS components.

3.4.2.1 Aging Effects

Tables 3.4-1, 3.4-2, and 3.4-3 of the LRA identify the following applicable aging effects:

- loss of material of carbon steel in treated water, borated water, lubricating oil

- air/gas, outdoor air, and containment air environments

- loss of material and/or cracking of stainless steel in treated water, lubricating oil and buried environments

- loss material and/or cracking of nickel alloy in treated water environment

- loss of mechanical closure integrity of carbon steel in borated water environment

The only parts of systems or components considered to be inaccessible for inspection are those that are buried or embedded/encased in concrete. These environments are addressed as part of the AMR process and are identified in Table 3.0-2, “External Service Environments,” of the LRA. Potential aging effects associated with these environments are reviewed, and those aging effects requiring management are identified along with the credited AMPs. The only portion of the SPCS containing inaccessible piping is auxiliary feedwater, which contains sections of buried and embedded stainless steel piping.

In RAI 3.4-1, the staff requested that the applicant explain why moisture and liquid pooling effects in an internal air/gas environment were not considered as an aging effect for stainless steel components. In its response dated September 26, 2002, the applicant stated the following:

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

This position is consistent with that accepted by the NRC previously for similar LRA reviews. The staff finds the applicant’s response reasonable and acceptable. On this basis, the RAI 3.4-1 concerns are considered resolved.

In RAI 3.4-2, the staff requested that the applicant explain why the effects of humidity in an external environment are not considered to cause aging that leads to a loss of preload for carbon steel bolts. In its response dated September 26, 2002, the applicant stated:

> Although the LRA identifies bolting (mechanical closures) material as carbon steel, the actual bolting standard for St. Lucie Units 1 and 2 piping components is low alloy steel ASTM A193, Grade B7. This material provides increased corrosion resistance over plain carbon steel. The bolting associated with Main Steam, Auxiliary Steam, Turbine, Main Feedwater and Steam Generator Blowdown is typically in a dry environment, coated with a lubricant, and exposed to temperatures greater than 212 °F. Therefore, moisture is not present on the surfaces of piping or associated bolting, and as a result loss of material due to general corrosion does not require management.
>
> Review of the St. Lucie plant experience, which was performed as part of the aging management review (AMR) process, confirmed that no loss of mechanical closure integrity has occurred due to general corrosion of bolting. Review of industry experience also confirms that general corrosion of bolting has not been a major concern and therefore is not an aging effect requiring management.
>
> Aging effects associated with bolting are described in the LRA, Appendix C, Section 5.4, Loss of Mechanical Closure Integrity. The only aging effect determined to require management associated with bolting is loss of mechanical closure integrity due to boric acid corrosion for components in proximity to borated water systems.

This position is consistent with that previously accepted by the NRC as part of similar LRA reviews. The staff finds the applicant's response reasonable and acceptable. Based on the above discussion, the RAI issue is considered resolved.

In RAI 3.4-3, the staff requested that the applicant justify the exclusion of flow-accelerated corrosion (FAC) as an aging mechanism that can cause wall thinning in auxiliary feedwater piping components. The scope of the FAC program includes main feedwater, blowdown, and main steam and turbine, but not auxiliary feedwater piping and components.

In its response dated September 26, 2002, the applicant stated:

> The St. Lucie Flow Accelerated Corrosion Program is based on industry consensus standard, NSAC-202L-R2, Recommendations for an Effective Flow Accelerated Corrosion Program. This document states in Section 4.2.2 that:
>
> Some susceptible systems, or portions of systems, can be excluded from further evaluation due to their relatively low level of susceptibility. Based on both laboratory and plant experience, the following systems can be safely excluded from further evaluation:
>
> Systems with no flow, or those that operate less than 2 percent of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F less than 2 percent of the plant operating time.

The applicant also confirmed that the auxiliary feedwater at St. Lucie is operated for less than 2 percent of the plant operating time. As a result, loss of material due to flow accelerated corrosion is not an aging effect requiring management for auxiliary feedwater.

The staff finds that the applicant's response satisfactorily addresses the staff's concern because it is consistent with industry consensus standards and the staff position. On this basis, the RAI issue is considered to be resolved.

In RAI 3.4-4, the staff requested that the applicant explain how the Boric Acid Wastage Surveillance Program manages the aging effects associated with elevated temperatures and stress levels to prevent loss of preload in mechanical bolting. In its response dated September 26, 2002, the applicant stated:

> The Boric Acid Wastage Surveillance Program is not credited for managing aging effects associated with elevated temperatures and stress levels to prevent loss of pre-load in mechanical joints.
>
> As discussed in LRA Appendix C, Subsection 5.4, "Loss of Mechanical Closure Integrity," the effect of loss of pre-load resulting from temperature effects and cyclic loading is external leakage of the internal fluid at a mechanical joint. With the exception of borated water leaks, there are no aging effects requiring management associated with external leakage of a mechanical joint. Loss of mechanical closure integrity resulting from borated water leaks is addressed in the LRA as discussed below.
>
> When external leakage involves borated water, the aging effect of concern is loss of material due to aggressive chemical attack (i.e., boric acid corrosion of carbon or low-alloy steel bolting). Therefore, the LRA addresses loss of mechanical closure
>
> Integrity resulting from the external environment of "borated water leaks" and credits the Boric Acid Wastage Surveillance Program for management of this aging effect.

This position is consistent with that previously accepted by the NRC as part of similar LRA reviews. The staff finds that the applicant's response satisfactorily addresses the staff's concern and the RAI issue is considered resolved.

The applicant provided references to St. Lucie plant-specific as well as industry-wide experience to support its identification of applicable aging effects for steam and power conversion systems. The staff concludes that, on the basis of the description of the internal and external environments and material of fabrication for these systems, the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.4.2.2 Aging Management Programs

In Section 3.4 of the LRA, the applicant identifies the following eight AMPs that are utilized to manage the aging effects associated with the structures and component of the steam and power conversion systems.

- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program
- Galvanic Corrosion Susceptibility Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program
- Condensate Storage Tank Cross-Connect Buried Pipe Inspection Program
- Pipe Wall Thinning Program

The staff evaluated the eight AMPs associated with the SPCS to determine if they contain the essential elements needed to provide adequate aging management of the components in the SPCS so that there is reasonable assurance that the components will perform their intended functions in accordance with the CLB for the period of extended operation. Seven of the AMPs are common to several systems and are evaluated in Section 3.0.5 of this SER. The condensate storage tank cross-connect buried piping inspection (Unit 1 only) is a system-specific AMP and is evaluated in Section 3.4.0.1 of this SER.

On the basis of the information provided, the staff finds that the above-listed eight AMPs are appropriate and acceptable for managing the aging effects associated with the components.

3.4.3 Conclusion

The staff has reviewed the information in LRA Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4 "Steam and Power Conversion Systems," as well as the applicant's responses to the staff's RAIs. On the basis of this review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that aging effects associated with the SPCS will be adequately managed so that there is a reasonable assurance that the intended functions of these systems will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). With the exception of confirmatory items 3.0.2.2-1, 3.0.5.1-1, and 3.0.5.4-1, the staff also concludes that the FSAR supplements contain an appropriate summary description of the programs and activities for managing the effects of aging for the steam and power conversion system as required by 10 CFR 54.21(d).

3.5 Aging Management of Structures and Structural Components

In Section 3.5, "Structures and Structural Components," of the LRA, the applicant describes the AMR for structures and associated components. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the structures and components. The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effect of aging on the structures and structural components will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

The structures include the following:

- containments
- component cooling water areas
- condensate polisher building
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fire rated assemblies
- fuel handling buildings
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

In Section 2.4 of the LRA, the applicant provides a description of these structures and identifies the structures and components requiring an AMR for license renewal. In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," the applicant provides a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d).

3.5.0 Aging Management Programs

3.5.0.1 ASME Section XI, Subsection IWE Inservice Inspection Program

The ASME Section XI, Subsection IWE Inservice Inspection Program is described in Section 3.2.2.2 of Appendix B to the LRA. This program provides aging management of the containment buildings for St. Lucie Units 1 and 2. The staff reviewed the LRA to determine whether the applicant has demonstrated that the ASME Section XI, Subsection IWE Inservice Inspection Program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.1.1 Summary of Technical Information in the Application

Chapter 3 of the LRA identifies the specific structural component/commodity groups that credit the ASME Section XI, Subsection IWE Inservice Inspection Program for aging management. Instead of describing the 10 elements relevant to the program, the LRA states that the ASME Section XI, Subsection IWE Inservice Inspection Program is consistent with the 10 attributes of aging management programs XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," specified in the GALL. Moreover, the LRA explains that for St. Lucie, Units 1 and 2, leak rate testing in accordance with 10 CFR Part 50, Appendix J, is included as Category E-P in the ASME Section XI, Subsection IWE Inservice Inspection Program. The currently applicable ASME code for the ASME Section XI, Subsection IWE Inservice Inspection Program is identified in FPL Letters L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7 of the LRA], and L-2000-227, dated November 13, 2000, for Unit 2 [Reference B-10 of the LRA].

The LRA also provides the operating experience based on the inspection of the containments. The operating experience is summarized as follows:

- Degraded coatings without corrosion were observed on several Unit 1 electrical penetrations.

- Missing coatings were identified on the Unit 1 containment dome.

- Pitting was observed on the Unit 2 containment vessel exterior in the vicinity of the annulus floor. The maximum depth was analyzed and determined to be acceptable. The affected area was coated and follow-up inspections were performed.

- The Unit 2 containment personnel airlock outer door handwheel shaft seal failed during the semi-annual strongback test. The cause was determined to be misalignment, and therefore, not age related.

- Cracking of the moisture barrier between the steel containment vessel and the concrete floor was observed on Unit 2. Sealant material was removed and the containment vessel was inspected. Minor corrosion was observed, but no vessel repairs were required.

- Degraded coatings and minor corrosion were observed at a piping penetration on Unit 2. The area was cleaned and recoated in accordance with plant procedures.

Based upon the above, the applicant concluded that the continued implementation of the ASME Section XI, Subsection IWE Inservice Inspection Program will ensure that the intended functions of the systems and components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.1.2 Staff Evaluation

The staff verified that the components, as identified in Table 3.5-2 of the LRA, to which the ASME Section XI, Subsection IWE Inservice Inspection Program applies are commensurate with the intent of the GALL Report, Programs XI.S1 and XI.S4. The staff finds the process acceptable. The staff considers the XI.S1 a containment condition monitoring program, and XI.S4 a containment leakage monitoring program. Both programs are needed to ensure the intended functions (functions 1, 2, 7, and 10 of Table 3.5-1 of the LRA) of the containments. The applicant will implement GALL Program XI.S4 in accordance with the requirements of the plant technical specifications. The staff finds this acceptable.

Table 3.5-2 of the LRA indicates that the aging management of the containment bellows is included within the ASME Section XI, Subsection IWE Inservice Inspection Program. Recognizing the susceptibility of the bellows to cracking due to transgranular stress corrosion cracking (see NRC Information Notice 92-20), the staff asked the applicant to provide the operating experience related to the condition of bellows at St. Lucie Units 1 and 2 and the method used to detect degradation of the inaccessible bellows (RAI B.3.2.2-1).

By letter dated September 26, 2002, the applicant provided the following response:

> NRC Information Notice 92-20 "Inadequate Local Leak Rate Testing" addresses circumstances involving local leak rate testing and an instance where the cause of measured leakage was due to bellows cracking apparently for an in-line bellows (i.e., bellows that are an integral part of the process piping system). The events described by the information notice occurred while testing bellows configurations routinely utilized in boiling water reactor type power plants, and the root cause of the identified cracking is not addressed in the notice.
>
> The containment vessel piping penetration bellows that are installed at St. Lucie Units 1 and 2 are predominantly structural type bellows, designed such that the bellows are not subjected to piping operating system parameters (i.e., not part of the process line pressure boundary). Aging management review results (LRA Table 3.5-2, page 3.5-37) concluded that the stainless steel (expansion joint) portions of the penetration bellows exposed to containment air or indoor-not-air-conditioned environments do not experience aging effects requiring management.
>
> St. Lucie plant-specific operating experience has not identified cracking of these bellows as an aging effect requiring management. Bellows that form a portion of the containment leak tight boundary are leak rate tested in accordance with ASME Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2, page B-26 - Appendix J leak rate testing).

Considering the operating experience stated in the response, the staff considers that the two-ply bellows at St. Lucie are testable under Type B testing of the containment penetrations, and that the integrity of the bellows will be maintained through the Appendix J testing during the period of license renewal. Therefore, the staff finds this acceptable.

The staff also requested clarification of the testing of containment isolation valves (RAI B.3.2.2-2), since GALL Program XI.S4 provides an option for leakage testing of containment isolation valves either (1) under Type C test, or (2) along with the tests of the systems containing the containment isolation valves. By letter dated September 26, 2002, the applicant provided the following response.

> Currently, all St. Lucie plant containment isolation valves that require testing under 10 CFR 50, Appendix J, are tested per Appendix J, Option B, Type C test, as part of the AMSE (sic. ASME) Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2 page B-26). Currently there are no plans to change these test methods during the extended period of operation.

The staff considers the option chosen by the applicant acceptable, as it will comply with the requirements of Option B of Appendix J, as approved by the staff in the plant technical specifications.

The staff also requested information related to the applicant's operating experience with the containment leak rate testing (RAI B.3.2.2-3). In response, by letter dated September 26, 2002, the applicant listed the reports it had submitted to NRC after each containment leak rate testing since operation of each unit. The staff reviewed the reports and discovered that the procedures used to conduct Type A, Type B, and Type C testing have been modified and improved with time based on the industry experience reflected in various revisions of ANSI/ANS-56.8, “Containment System Leakage Testing Requirements.” The staff concludes that continued use of the procedures to conduct the tests and report the test results for the extended period of operation will ensure that the containment leaktight integrity will be verified, and the staff finds this acceptable.

The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff’s review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.S1 and XI.S4 in the FSAR Supplements’ descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.5.0.1.3 FSAR Supplement

The staff reviewed Section 18.2.2.2 of the FSAR supplement summary description of the ASME Section XI, Subsection IWE Inservice Inspection Program in Appendix A of the LRA, and the Appendix J leak rate testing program for containment leak rate testing described in the plant technical specifications. Pending completion of confirmatory item 3.0.2.2-1, the staff finds that the information provided in the FSAR supplement provides an adequate summary of the program activities as required by 10 CFR 54.21(d).

3.5.0.1.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant’s claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.5.0.2 ASME Section XI, Subsection IWF Inservice Inspection Program

The ASME Section XI, Subsection IWF Inservice Inspection Program is described in Section B.3.2.2.3, of Appendix B to the LRA. This program provides for condition monitoring of component supports in several structures that are within the scope of license renewal. The staff reviewed the ASME Section XI, Subsection IWF Inservice Inspection Program to determine whether the applicant has demonstrated that this program will adequately manage the aging effects for the component supports that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.2.1 Summary of Technical Information in the Application

Section 3.2.2.3 of Appendix B to the LRA states that the ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with GALL Program XI.S3, “ASME Section XI, Subsection IWF.” The LRA states that the program is credited for aging management of Class 1, 2, and 3 component supports in the following structures:

- component cooling water areas
- condensate storage tank enclosures
- containments
- diesel oil equipment enclosures

- emergency diesel generator buildings
- fuel handling buildings
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- ultimate heat sink dam
- yard structures

The LRA also describes the operating experience with the ASME Section XI, Subsection IWF Inservice Inspection Program. The program is a condition monitoring program that provides for the implementation of ASME Code, Section XI, in accordance with the provisions of 10 CFR 50.55a. The 10-year examination plan provides a systematic guide for performing nondestructive examination of passive components in the scope of license renewal. Based on this, the applicant concluded that the ASME Section XI, Subsection IWF Inservice Inspection Program will adequately manage the aging effects so that there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.0.2.2 Staff Evaluation

The applicant stated that the ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with the 10 attributes of AMP XI.S3, "ASME Section XI, Subsection IWF," specified in the GALL. The staff verified that the components, as identified in Section 3 of the LRA, to which the ASME Section XI, Subsection IWF Inservice Inspection program applies are commensurate with the intent of the GALL Report Program. The staff review noted that, as indicated in Table 3.5-2 of the LRA, the containments contain safety-related piping and component supports, reactor vessel supports, pressurizer supports, reactor coolant pump supports, and steam generator supports, all manufactured from carbon steel, which are exposed to the containment air environment. The applicant credited the Subsection IWF Inservice Inspection Program for managing the aging effects (loss of material) for these piping and component supports. Tables 3.5-3, 3.5-5, 3.5-6, 3.5-7, 3.5-9, 3.5-11, and 3.5-12 of the LRA indicated, respectively, the component cooling water areas, condensate storage tank enclosures, diesel oil equipment enclosures, emergency diesel generator buildings, fuel handling buildings, intake structures, and reactor auxiliary buildings, which contain safety-related piping and component supports, manufactured from carbon steel, and are exposed to an indoor-not-air-conditioned or outdoor environment. Based on Tables 3.5-13, 3.5-15, and 3.5-16, the steam trestle areas, ultimate heat sink dam, and yard structures, respectively, also contain safety-related piping and component supports, manufactured from carbon steel, which are exposed to the outdoor environment. The applicant credited the Subsection IWF Inservice Inspection Program for managing the aging effect (loss of material) for these piping and component supports. The staff finds this acceptable because the components that credit this program are commensurate with the intent of the GALL program.

The applicant further stated that the Subsection IWF Inservice Inspection of the Class 1, 2, and 3 component supports has been conducted on both units since plant initial start-up. The visual examinations of Class 1, 2, and 3 component supports look for deformations or structural degradations, corrosion, and other condition that could affect the intended function of the support. Conditions noted during the inspection of component supports are documented on inspection reports. Loss of material has been identified for numerous supports. Evaluations have determined the loss of material was caused by general corrosion. The degraded supports were entered into the corrective action program, and repaired or replaced as appropriate. The staff finds that the past plant operation serves to demonstrate successful future performance of the ASME Section XI, Subsection IWF Inservice Inspection Program.

The staff inspected the ASME Section XI, Subsection IWF Inservice Inspection Program for acceptability and compared the programs 10 elements to the 10 elements discussed in GALL AMPs XI.S3. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff's review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.S3 in the FSAR Supplements' descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.5.0.2.3 FSAR Supplement

The staff reviewed the summary description of the ASME Section XI, Subsection IWF Inservice Inspection Program in Section 18.2.2.3 of the FSAR supplement in Appendix A of the LRA. With the exception of confirmatory item 3.0.2.2-1, the staff finds that the information provided in the FSAR supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and, therefore, provides an adequate summary of the program activities as required by 10 CFR 54.21(d).

3.5.0.2.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant's claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.5.0.3 Boraflex Surveillance Program

3.5.0.3.1 Summary of Technical Information in the Application

The applicant described its boraflex surveillance program in Section 3.2.3, "Boraflex Surveillance Program (Unit 1 only)," of Appendix B to the LRA. The staff reviewed the application to determine whether the applicant had demonstrated that the Boraflex Surveillance Program will adequately manage the applicable aging effects in the plants for the period of extended operation as required by 10 CFR 54.21(a)(3).

The Boraflex Surveillance Program, applicable only to Unit 1, is credited for managing the aging of spent fuel pool (SFP) storage rack panels for the period of extended operation. The Boraflex Surveillance Program is a performance monitoring program that manages the degradation of the panels in the spent fuel storage racks due to gamma irradiation. The Boraflex panels ensure that the reactivity of the storage fuel assemblies is maintained within required limits.

The applicant states that the Boraflex Surveillance Program is consistent with the 10 program elements of AMP XI.M22, "Boraflex Monitoring," as specified in NUREG-1801, Volume 2, "Generic Aging Lessons Learned (GALL) Report" dated April 2001. The applicant also states that commitment dates associated with implementation of this AMP are contained in

Appendix A of the LRA. The current program includes blackness testing to monitor parameters including physical conditions of the boraflex panels in terms of gap information, gap distribution, and gap size. Trending of the SFP silica concentration is conducted to give a qualitative indication of boron carbide loss from the panels. In addition, the applicant states that, during the extended license of operation, the Boraflex Surveillance Program will be enhanced to include areal density testing. Commitment dates associated with the enhancement to this program are contained in Appendix A of the LRA.

3.5.0.3.2 Staff Evaluation

The 10 program elements in the GALL Report, AMP XI.M22, “Boraflex Monitoring,” provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage the degradation of the panels in the spent fuel storage racks due to gamma irradiation. In Appendix B, Section 3.2.3, of the LRA, the applicant has stated that the program elements for the Boraflex Surveillance Program are consistent with those specified in Program XI.M22 of the GALL Report. The applicant retains the program description of the Boraflex Surveillance Program as well as the descriptions for the program’s 10 elements on record at the St. Lucie Nuclear Station. In addition, the program will be enhanced to include areal density testing. The testing will measure the Boron-10 areal density to ascertain the depletion of boron carbide from boraflex panels.

The staff inspected the Boraflex Surveillance Program for acceptability and compared the program’s 10 elements to the 10 elements described in GALL AMP XI.M22. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The staff’s review of the inspection findings is open item 3.0.2.2-1.

During a phone call on January 31, 2003, the applicant agreed to include a reference to GALL AMP XI.M22 in the FSAR Supplements’ descriptions of this AMP. This is Confirmatory Item 3.0.2.2-1.

3.5.0.3.3 FSAR Supplement

Section 18.2.3, of Appendices A1 and A2 of the LRA, provides the applicant’s FSAR supplement for the Boraflex Surveillance Programs at St. Lucie. The staff reviewed the section to verify that the information in the FSAR supplement provides an adequate summary of the program activities required by 10 CFR 54.21(d). With the exception of confirmatory item 3.0.2.2-1, the
staff finds the FSAR supplement sufficient.

3.5.0.3.4 Conclusion

The staff is in the process of reviewing the results of the AMR inspection. The inspection is complete, however, the report has not been issued. One purpose of the inspection was to verify the applicant’s claim that some AMPs are consistent with the GALL Report. The acceptability of this AMP is pending the results of open item 3.0.2.2-1.

3.5.1 Containments

3.5.1.1 Technical Information in the Application

The AMR results for the containment, which consists of the freestanding steel containment vessel surrounded by the reactor containment shield building, are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA identifies the components of the containment structure along with their (1) intended functions, (2) material, (3) environment, (4) aging effects, and (5) aging management programs.

Section 2.4.1 of the LRA states that each St. Lucie containment consists of the freestanding steel containment vessel surrounded by the reactor containment shield building. Each containment houses the reactor coolant systems and the reactor coolant system supports. Additionally, each containment houses and supports components required for plant refueling, including the polar crane, refueling cavity, and portions of the fuel handling system.

The materials of construction for the containment structure, as shown in Table 3.5-2 of the LRA, are steel, concrete, and miscellaneous materials such as silicone, elastomers, and lubrite plates.

The containment structure components are exposed to containment air, indoor (not air conditioned) and outdoor, borated water leaks, treated water, and a buried environment.

3.5.1.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in the containment structure:

- loss of material of carbon steel in containment air, indoor-not-air-conditioned, outdoor, or exposed to borated water leaks
- loss of material of galvanized carbon steel exposed to borated water leaks
- loss of material of stainless steel in treated water - borated
- loss of material of concrete in an outdoor environment
- loss of material and change in material properties for concrete in a buried environment
- loss of seal for elastomers exposed to containment air, indoor -not air conditioned, or treated water - borated

3.5.1.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in the containment structure:

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the containment structure will be adequately managed by these AMPs such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.1.2 Staff Evaluation

In addition to Section 3.5.1 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, “Scoping and Screening Results - Structures,” and the applicable AMP descriptions provided in Appendix B of the LRA, to determine whether the aging effects for the containment components have been properly identified and will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s AMR for the aging effects and the applicant’s programs credited for the aging management of the containment structural components at St. Lucie. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the containment components.

3.5.1.2.1 Aging Effects

<u>Concrete.</u> The applicant identifies loss of material and change in material properties as applicable aging effects for below-grade reinforced concrete structural components. However, for reinforced concrete in accessible portions of the containment structures, such as exterior walls and roofs, the applicant does not identify any applicable aging effects. In addition, the applicant does not identify any applicable aging effects for reinforced concrete located within the containment (interior shield walls, beams, slabs, missile shields, equipment pads) or for reinforced masonry block walls.

The staff considers cracking, change in material properties, and loss of material to be applicable aging effects for concrete containment components that are exposed to either sheltered interior or outdoor environments. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation depending on the stresses and strains, due to normal and incidental loadings, as well as the environment to which they are subjected. Concrete SCs subjected to sustained loading—such as crane or monorail operation—and/or sustained adverse environmental conditions—such as high temperatures, humidity, or chlorides—will degrade, thereby potentially affecting the intended function(s) of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects accentuate. On the basis of industry-wide evidence, the American Concrete Institute (ACI) has published a number of documents (e.g., ACI 201.1R, “Guide for Making a Condition Survey of Concrete,” ACI 224.1R, “Causes, Evaluation and Repairs of Cracks in Concrete Structures,” and ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures”) that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent characteristics of concrete structures to degrade, with time, if not properly managed. Similar observations of concrete aging, made by NRC staff, are detailed in NUREG-1522, “Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures.” As such, in RAI 3.5-1 the staff requested that the applicant identify AMPs that will be used to manage the aging effects for the concrete containment components listed in Table 3.5-2 of the LRA.

By letter dated September 26, 2002, as supplemented by letter dated November 27, 2002, the applicant stated the following:

> The analysis of possible aging effects for reinforced concrete components in the Containments and Other structures are summarized in the LRA Subsections 3.5.1.3 and 3.5.2.3 (page 3.5-9 and 3.5-24, respectively). The analysis is based on concrete material properties, the applicable environments, and years of operating experience. The analysis concludes that concrete structures exposed to aggressive environments require aging management, and concrete structures not exposed to aggressive environments do not require aging management.
>
> However, based on specific direction from NRC staff, license renewal applicants are required to implement an aging management program to manage aging of concrete structures. FPL proposes to credit the Systems and Structures Monitoring Program (LRA Appendix B Subsection 3.2.14 page B-57) for managing aging (including cracking, loss of material, and change in material properties) of the accessible reinforced concrete structures listed in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93).

The applicant's commitment to monitor concrete aging effects in accessible areas is acceptable to the staff. The applicant has decided to use the Systems and Structures Monitoring Program to manage concrete aging, which is reviewed in Section 3.0.5.10 of this SER. The staff considers the applicant's response to RAI 3.5-1 to be adequate with respect to managing the aging of concrete structural components for the period of extended operation.

For unreinforced concrete masonry block walls, the applicant has committed to manage cracking for the period of extended operation. However, for reinforced concrete masonry block walls, the applicant did not identify any applicable aging effects. Reinforced concrete masonry block walls are found in the containment structure (LRA Table 3.5-2). In RAI 3.5-12, the staff requested that the applicant justify this conclusion. In response, the applicant stated the following :

> Cracking of reinforced masonry block walls is not an aging effect requiring management since the reinforcing steel effectively controls cracking thus preventing a loss of intended function. During IE Bulletin 80-11, "Masonry Wall Design," walkdowns, no significant cracking was identified. Furthermore, after many years of service, reinforced masonry block walls at St. Lucie have not exhibited cracking that could lead to a loss of intended function. For that reason, cracking of reinforced masonry block walls is not an aging effect requiring management. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

The applicant's decision to not manage the aging of reinforced concrete masonry walls is not acceptable to the staff. The staff does not distinguish between the AMRs for general reinforced concrete components, which are discussed above and in RAI 3.5-1, and those for reinforced concrete masonry block walls. In a letter dated December 23, 2002, the applicant modified its response to RAI 3.5-12 by stating that the Systems and Structures monitoring program will be used to manage cracking for reinforced concrete masonry block walls listed in LRA Table 3.5-2. The applicant's decision to manage cracking for reinforced concrete masonry walls is acceptable to the staff. Therefore, RAI 3.5-12 is considered to be resolved.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/ground water environment is non-aggressive. The applicant, however, acknowledges that the soil/ground water environment at St. Lucie is potentially aggressive. In RAI 3.5-9, the staff requested that the applicant describe the condition of below-grade concrete structural components and provide the average levels of contaminants (chlorides and sulfates) and pH level in the ground water at the St. Lucie site. By letter dated September 26, 2002, the applicant stated that the intake structures have experienced concrete degradation that warranted corrective actions and that other concrete structures located below ground water have not exhibited any indications of concrete degradation. The applicant also provided the following ground water chemistry data from UFSAR Section 2.4.13.2:

> Data from on-site wells of both pre-construction and construction periods compare closely with regard to chloride content. Preconstruction piezometer readings indicated concentrations from 10,000 to 25,000 ppm. Information obtained from samples taken throughout the site during dewatering at an average depth of 90 feet had 10,000 to 23,000 ppm chlorides and 1,000 to 4,000 ppm sulfides.

Water samples obtained from various on-site piezometers indicate pH values ranging from 5.5 to 7.1, and sulfates ranging from 387 to 2709 ppm (see UFSAR Table 2.4-3).

NUREG-1557 defines an aggressive environment for concrete to be pH less than 5.5, sulfates greater than 1500 ppm, and chlorides greater than 500 ppm. Since the St. Lucie ground water chemistry exceeds these levels, there is a potential for below-grade concrete structural components to degrade for the period of extended operation.

The staff also requested in RAI 3.5-9 that the applicant provide grade elevations and ground water level fluctuations at St. Lucie. In response, the applicant referenced UFSAR Section 2.5.4.11 which states that the existing grade around the unit at approximately elevation 0 feet was raised to elevation plus 18 feet with compacted fill. The ground water level was estimated to be the normal high water level in the Indian River at elevation plus 2 feet. Fluctuations in the ground water are influenced by tidal changes in the Atlantic Ocean to the east, moderated by the Indian River to the west.

Due to the potential for an aggressive below-grade soil/ground water environment at St. Lucie, the applicant has committed, as shown in Table 3.5-2 of the LRA, to manage below-grade reinforced concrete structural components using the Systems and Structures Monitoring Program.

<u>Steel.</u> The applicant identified (1) loss of material of carbon steel in containment air, indoor and outdoor air, or exposed to borated water leaks, (2) loss of material of galvanized carbon steel exposed to an outdoor (wetted) environment or borated water leaks, and (3) loss of material of stainless steel in treated (borated) water as applicable aging effects for steel components in the containment structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel, galvanized carbon steel, and stainless steel components in the containment structure. However, the staff noted in RAI 3.5-2, that although loss of material is identified as an aging effect for galvanized carbon steel exposed to an outdoor (wetted) environment, no aging effects are identified in Table 3.5-2 for galvanized carbon steel components exposed to an outdoor environment that is not designated as being “wetted.” As such, the staff requested that the applicant justify the conclusion that there are no applicable aging effects for galvanized carbon steel in an outdoor environment and to distinguish between a “wetted” outdoor environment and an outdoor environment.

In response to Item 1 of RAI 3.5-2, by letter dated September 26, 2002, the applicant stated the following:

> As noted in LRA Appendix C Section 5.1 (page C-11), galvanized steel is not susceptible to general corrosion except where buried, submerged, or subject to wetting other than humidity, such as salt spray. A "wetted" outdoor environment is one in which standing water accumulates or significant salt spray is present. Both wetted and non-wetted galvanized structures were identified by review of St. Lucie plant-specific operating experience and direct inspection of galvanized structures, and both types are identified in LRA Tables 3.5-2 through 3.5-16 (pages 3.5-35 through 3.5-93). Based on 25+ years of St. Lucie plant-specific operating experience, non-wetted galvanized structures, as defined in LRA Appendix C, Section 5.1 (page C-11), do not require aging management. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

The applicant's position regarding the potential for aging of wetted and non-wetted galvanized steel structures is based on over 25 years of operating experience. To further verify the applicant's conclusions the staff conducted an on-site inspection of galvanized carbon steel components in an outdoor environment. The inspector's verified that the applicant's aging management review findings for galvanized carbon steel components in an outdoor environment are correct. Inspectors determined that there is a difference between a "wetted" outdoor environment and a "non-wetted" outdoor environment and that only those galvanized carbon steel components in wetted (significant salt spray or standing water) outdoor environment are susceptible to loss of material. Pending completion of confirmatory item 3.0.2.2, the staff considers RAI 3.5-2 closed.

In RAI 3.5-6, the staff requested that the applicant provide further justification for concluding that stainless steel fuel transfer tube expansion bellows, located in a containment air environment, do not require aging management for cracking. By letter dated September 26, 2002, the applicant stated that the fuel transfer tube expansion bellows are not exposed to process fluid (i.e., borated refueling water). Also, the fuel transfer tube penetrations are not subject to elevated temperatures and, therefore, are not subject to thermal fatigue. The applicant concluded that there are no aging effects requiring management for fuel transfer tube expansion bellows in a containment air environment. The staff concurs with the applicant's findings that the environment, indicated above, is such that there are no aging effects requiring management for fuel transfer tube expansion bellows.

<u>Elastomers (moisture barriers, seals).</u> Table 3.5-2 of the LRA identifies loss of seal as an aging effect for elastomer components in the containment with the exception of the fuel transfer tube penetration flexible membranes in the annulus. The staff concurs with the applicant's identification of loss of seal as an applicable aging effect for elastomers associated with the primary containment pressure boundary components. However, in RAI 3.5-3, the staff requested that the applicant explain why there are no aging effects for the silicone fuel transfer tube penetration flexible membranes in the annulus. By letter dated September 26, 2002, the applicant stated the following:

> The fuel transfer tube flexible membranes provide a seal between each containment annulus and the outdoor environment where the fuel transfer tubes penetrate the shield buildings. These membranes serve as a ventilation boundary for Shield Building Ventilation. These flexible membranes are made of radiation resistant silicone rubber designed for the subject environment.
>
> As discussed in LRA Subsection 4.5.2 (page 4.5-2), the fuel transfer tube penetrations are not subject to elevated temperatures. Therefore, significant movements due to temperature fluctuations that could result in misalignment and loss of seal are not credible. Consequently, aging management of the seals is not required.

Since the fuel transfer tube penetrations are not subjected to elevated temperatures, the staff concurs with the applicant's evaluation of the potential aging effects for these flexible membranes.

Bronze/Graphite. Table 3.5-2 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates in the containment structure. In RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. By letter dated September 26, 2002, the applicant stated the following:

> As described in literature provided by Lubrite Technologies (formerly Merriman), Lubrite products are solid, permanent, completely self-lubricating, and require no maintenance. The Lubrite proprietary lubricant is a custom compound mixture of metals, metal oxides, minerals, and other lubricating materials combined with a lubricating binder. The Lubrite lubricants used in nuclear applications are designed for the environments to which they are exposed.
>
> As noted in LRA Subsection 2.3.1.6 (page 2.3-7), the Unit 1 steam generators were replaced in 1997. The Lubrite plates for the steam generator upper lateral supports were also replaced. The original Lubrite plates showed no evidence of degradation.
>
> FPL performed an extensive search of industry and St. Lucie plant-specific operating experience utilizing various sources, including the INPO website. No reported instances of Lubrite plate degradation or failure to perform their intended function were identified. Consequently, there are no known aging effects that would lead to a loss of intended function. This position is consistent with that accepted by NRC as part of the Turkey Point Units 3 and 4 LRA review.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of Lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Item 2 of RAI 3.5-3 to be closed.

3.5.1.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in the containment structure:

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

The Boric Acid Wastage Surveillance Program, Chemistry Control Program, Periodic Surveillance and Preventive Maintenance Program, and Systems and Structures Monitoring Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff review of the common AMPs is in Section 3.0.5 of this SER. The staff evaluations of the ASME Section XI, Subsection IWE Inservice Inspection Program and the ASME Section XI, Subsection IWF Inservice Inspection Program are in Section 3.5.0.1 and Section 3.5.0.2, respectively of this SER.

3.5.1.3 Conclusion

The staff has reviewed the information in Section 3.5.1 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, with the exception of open item 3.0.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the containment structure will be adequately managed, so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2 Other Structures

3.5.2.1 Technical Information in the Application

The AMR results for structures outside containment are presented in Table 3.5-3 through 3.5-16 of the LRA. Each of these AMR tables lists the (1) component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs. The structural components listed in Tables 3.5-3 through 3.5-16 of the LRA are in the following structures:

- component cooling water areas
- condensate polisher building
- condensate storage tank enclosures
- diesel oil equipment enclosures
- emergency diesel generator buildings
- fire rated assemblies
- fuel handling buildings
- intake, discharge, and emergency cooling canals
- intake structures
- reactor auxiliary buildings
- steam trestle areas
- turbine buildings
- ultimate heat sink dam
- yard structures

A brief description of each of the above structures is provided in Section 2.4.2, “Other Structures,” of the LRA. The materials of construction identified in Tables 3.5-3 through 3.5-16 of the LRA for each of the above structures are (1) steel, (2) concrete, (3) polymer, (4) elastomers, (5) earth fill, (6) caulking and sealants, (7) PVC, and (8) fire protection materials. These materials are exposed to outdoor, outdoor (wetted), indoor-air-conditioned, indoor-not-air-conditioned, buried, borated water leaks, treated water - borated, and raw water - saltwater.

3.5.2.1.1 Aging Effects

Tables 3.5-3 through 3.5-16 of the LRA identify the following applicable aging effects for components in structures outside containment:

- loss of material
- change in material properties
- cracking
- loss of seal

3.5.2.1.2 Aging Management Programs

Tables 3.5-3 through 3.5-16 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside containment:

- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boraflex Surveillance Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in structures outside the containment will be adequately managed by these AMPs such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 Staff Evaluation

In addition to Section 3.5.2 of the LRA, the staff reviewed the pertinent information provided in Section 2.4.2, “Other Structures,” and the applicable AMP descriptions provided in Appendix B of the LRA, to determine whether the aging effects for the components in structures outside the containment have been properly identified and will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s AMR for the aging effects and the applicant’s programs credited for the aging management of the components in structures outside the containments at St. Lucie. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the components in structures outside the containment.

3.5.2.2.1 Aging Effects

Concrete and Masonry Block Walls: Tables 3.5-3 through 3.5-16 of the LRA identify change in material properties (CMP), loss of material (LM), and cracking (CR) as applicable aging effects for unreinforced and reinforced concrete structural components in the following structures outside the containment:

- component cooling water areas—equipment pedestals, walls, slabs (LM, CMP)
- fuel handling building—unreinforced concrete masonry block walls (CR)
- intake, discharge, and emergency cooling canals—erosion protection- outdoor (LM), raw water—saltwater (LM, CMP)
- intake structures—slabs, walls, and roofs, raw water—salt water (LM, CMP), pump pedestals (LM, CMP)
- reactor auxiliary buildings—reinforced concrete below ground water (exterior) - buried (LM, CMP), unreinforced masonry block walls (CR)

- steam trestle areas—reinforced concrete below ground water (LM, CMP)
- ultimate heat sink dam—walls, roofs, slabs (LM, CMP)

For all other reinforced concrete structural components located above ground water in outdoor, sheltered, or buried environments, Tables 3.5-3 through 3.5-16 do not identify any applicable aging effects.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all of the concrete components in each of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete SCs is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for timely identification and correction of degraded conditions. In addition, the staff does not distinguish between the aging management requirements for general reinforced concrete structural components and those for reinforced masonry components. In RAI 3.5-1, the staff requested further information regarding the applicant's determination that management of concrete aging is required for only select components. In response to RAI 3.5-1, by letter dated September 26, 2002, the applicant stated that it disagrees with the staff's position regarding the aging management of concrete structures; however, the applicant decided that it will manage concrete aging for the period of extended operation. The applicant specifically stated that it will monitor concrete structural components for loss of material, cracking, and change in material properties through the Systems and Structures Monitoring Program. Since this commitment from the applicant covers all of the concrete components listed in Tables 3.5-3 through 3.5-16, this response is considered to be acceptable to the staff. RAI 3.5-1 is considered closed with respect to the concrete components in structures outside the containment. However, in response to RAI 3.5-12, the applicant stated that it does not plan to manage the aging of reinforced concrete masonry block walls for the period of extended operation. Reinforced concrete masonry block walls are found in the auxiliary building (LRA Table 3.5-12). As noted in Section 3.5.1.2.1, the staff does not distinguish between the aging management requirements for general reinforced concrete structures and those for reinforced concrete masonry block walls. In a letter dated December 23, 2002, the applicant modified its response to RAI 3.5-12 by stating that the System and Structures Monitoring Program will be used to manage cracking for reinforced concrete masonry block walls listed in LRA Table 3.5-12. The applicant's decision to manage cracking for reinforced concrete masonry walls is acceptable to the staff. Therefore, RAI 3.5-12 is considered to be closed.

For the below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/ground water environment is non-aggressive. The applicant, however, acknowledges that the soil/ground water environment at St. Lucie is potentially aggressive. This conclusion is based on pH, chloride, and sulfate levels measured in ground water samples at St. Lucie (UFSAR Section 2.4.13.2), which are listed above in Section 3.5.1.2.1 of this SER. Due to the potential for an aggressive below-grade soil/ground water environment at St. Lucie, the applicant has committed, as shown in Tables 3.5-3 through 3.5-16 of the LRA, to manage below-grade reinforced concrete structural components using the Systems and Structures Monitoring Program.

Steel: Tables 3.5-3 through 3.5-16 of the LRA identify loss of material and change in material properties as applicable aging effects for steel components exposed to the following environments:

- loss of material: carbon steel—outdoor, indoor (not air conditioned), borated water leaks, buried

- loss of material and change in material properties—carbon steel—raw water (salt water), buried, outdoor, indoor—not-air-conditioned

- carbon steel galvanized—outdoor (wetted), borated water leaks

- stainless steel—treated water (borated)

The staff concurs with the applicability of loss of material and change in material properties as an aging effect for steel components exposed to the above environments in structures outside the containment. However, the staff noted in RAI 3.5-2, that although loss of material is identified as an aging effect for galvanized carbon steel exposed to an outdoor (wetted) environment, no aging effects are identified in Tables 3.5-3 through 3.5-16 for galvanized carbon steel components exposed to an outdoor environment that is not designated as being "wetted." As such, the staff requested that the applicant justify the conclusion that there are no applicable aging effects for galvanized carbon steel in an outdoor environment and to distinguish between a "wetted" outdoor environment and an outdoor environment. The applicant's entire response to RAI 3.5-2 can be found in Section 3.5.1.2.1 of this SER. In summary, the applicant stated that galvanized steel is not susceptible to general corrosion except where buried, submerged, or subject to wetting other than humidity, such as salt spray. A "wetted" outdoor environment is one in which standing water accumulates or significant salt spray is present. In addition, the applicant stated that based on 25+ years of St. Lucie plant-specific operating experience, non-wetted galvanized structures do not require aging management. The applicant's position regarding the potential for aging of wetted and non-wetted galvanized steel structures is based on over 25 years of operating experience. To further verify the applicant's conclusions the staff conducted an on-site inspection of galvanized carbon steel components in an outdoor environment. The inspector's verified that the applicant's aging management review findings for galvanized carbon steel components in an outdoor environment are correct. Inspectors determined that there is a difference between a "wetted" outdoor environment and a "non-wetted" outdoor environment and that only those galvanized carbon steel components in wetted (significant salt spray or standing water) outdoor environment are susceptible to loss of material. Pending completion of confirmatory item 3.0.2.2, the staff considers RAI 3.5-2 closed.

In RAI 3.5-3, the staff requested that the applicant justify its AMR conclusion regarding the carbon steel plate fire-sealed isolation joint. Contrary to other carbon steel components that are located in an indoor-not-air-conditioned environment, the applicant did not identify loss of material as an applicable aging effect for the carbon steel plate fire-sealed isolation joint. In response to RAI 3.5-3, by letter dated September 26, 2002, the applicant stated the following:

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

Since aging of the carbon steel closure plate, which is provided on both sides of the fire-sealed isolation joint, will not cause a loss of intended function for the fire-sealed isolation joint, the staff concurs with the applicant's conclusion that there are no aging effects requiring management for the closure plates. Item 4 of RAI 3.5-3 is considered closed.

Fire Protection Materials. The fire protection materials identified in Table 3.5-8 of the LRA are (1) Marinite board, (2) Durablanket, (3) silicone, (4) Quelpyre, (5) ethafoam, (6) Dymeric sealant, (7) ceramic fiber, (8) Thermo-lag, (9) fire retardant coatings, (10) insulated blankets, (11) Cerablanket, and (12) aluminum. The applicant states that there are no aging effects for the above materials and therefore no AMPs are required for fire protection materials. The applicant's AMR conclusion for the fire protection materials is consistent with NUREG-1801 (GALL Report), which only calls for aging management of fire barrier penetration seals that are exposed to an outdoor environment. Since the fire protection materials identified in Table 3.5-8 of the LRA are exposed only to indoor environments, the staff concludes that these materials do not require aging management for the period of extended operation.

Miscellaneous Materials. The miscellaneous materials identified in Tables 3.5-3 through 3.5-16 of the LRA are (1) earth fill, (2) polyvinyl chloride (PVC), (3) silicone, (4) elastomers, (5) weatherproofing materials (caulking and sealants), and (6) boron impregnated polymer (boraflex). The applicant identified change in material properties as an applicable aging effect for the boraflex panels, and loss of seal for the elastomer door seals and weatherproofing. No aging effects are identified for either PVC or earth fill. The staff concurs with aging effects identified by the applicant for the boraflex panels, elastomer door seals, and weatherproofing. However, in RAI 3.5-5, the staff requested that the applicant justify its AMR conclusion regarding the earthen canal dikes in the intake, discharge, and emergency cooling canals. Earthen water-control structures are susceptible to loss of material and loss of form resulting from erosion, settlement, sedimentation, waves, currents, surface runoff, and seepage. By letter dated September 26, 2002, the applicant stated the following:

> As described in LRA Subsection 2.4.2.9 (page 2.4-12), the emergency cooling canal and the portion of the intake canal between the emergency cooling canal and the intake structures are in the scope of license renewal. Erosion of the associated earthen canal dikes is prevented by concrete erosion protection installed on the dike embankments. Aging management of the concrete erosion protection is performed by the Systems and Structures Monitoring Program (LRA Appendix B, Subsection 3.2.14, page B-57). Therefore, because the concrete erosion protection prevents aging of the earthen dikes, aging management of the earthen dikes is not required.

Since the earthen canal dikes are covered over by concrete, the staff concurs with the applicant's conclusion that aging management of the earthen dikes is not required. To further verify the applicant's conclusions, the staff conducted an inspection of the earthen canal dikes as part of the St. Lucie aging management review inspection. The staff inspectors verified that in-scope portions of the earthen canal dikes are protected by concrete erosion protection. Thus, pending completion of confirmatory item 3.0.2.2-1, the staff concluded that loss of material and loss of form are not applicable aging effects for the earthen canal dikes and RAI 3.5-5 is considered closed.

3.5.2.2.2 Aging Management Programs

Tables 3.5-3 through 3.5-16 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment:

- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boraflex Surveillance Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems and Structures Monitoring Program

The Boric Acid Wastage Surveillance Program, Chemistry Control Program, Fire Protection Program, Periodic Surveillance and Preventive Maintenance Program, and Systems and Structures Monitoring Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff review of the common AMPs is in Section 3.0.5 of this SER. The staff evaluation of the ASME Section XI, Subsection IWF Inservice Inspection Program is presented above in Section 3.5.0.2 of this SER and the evaluation of the Boraflex Surveillance Program is in Section 3.5.0.3.

3.5.2.3 Conclusion

The staff has reviewed the information in Section 3.5.2 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, with the exception of open item 3.0.2.2-1, the staff concludes the applicant has demonstrated that the aging effects associated with the components in structures outside the containment will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB for the period of extended operation.

3.6 Aging Management of Electrical and Instrumentation and Controls

The applicant described its AMR results of electrical/I&C components requiring AMR at St. Lucie Units 1 and 2, in Section 3.6 of the LRA. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effect of aging on the electrical/I&C components will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.0 System-Specific Aging Management Program

In Section 3.6 of the LRA, the applicant states that there are no AMPs required for non-environmentally qualified (non-EQ) cables and connectors nor for uninsulated ground conductors. However, in response to the staff's request for additional information (RAI 3.6-1), the applicant proposed an AMP for some non-EQ cables and connectors. The staff's evaluation of the proposed AMP follows.

3.6.0.1 Non-EQ Cables and Connections Aging Management Program

The staff requested in a letter dated July 1, 2002, that the applicant provide a description of an AMP for accessible non-EQ electrical cable cables and connections (connectors, splices, and terminal blocks) within the scope of license renewal located in the containment exposed to an adverse localized environment caused by radiation or moisture. In a letter dated September 26, 2002, the applicant proposed an AMP for the non-EQ cables and connections for power and instrumentation and controls (I & C) that are within the scope of license renewal.

3.6.0.1.1 Summary of Technical Information in the Application

In a letter dated September 26, 2002, the applicant states that based on the original St. Lucie cable routing design, plant specific operating experience, and periodic walkdowns that have been performed, there are no adverse localized environments caused by heat, radiation, or moisture present in areas where non-EQ cables and connections are located. As indicated in LRA Subsection 3.6.2.2 (page 3.6-9), the applicant performed an extensive review of St. Lucie plant operating experience associated with cables and connections, in part, to determine the existence of adverse localized environments. This review did not identify any adverse localized environments caused by heat, radiation, or moisture that might be detrimental to cables and connections. Occurrences of degraded cable are identified and dispositioned routinely through the corrective action and maintenance programs. Due to the absence of adverse localized environments caused by heat, radiation, or moisture in areas where non-EQ cables and connections are present, inspection of these non-EQ cables and connections would be of little value. However, based on discussions with the staff, the applicant proposed an AMP for non-EQ cables and connections in the St. Lucie containments. The non-EQ cables and connections managed by this program include those used in systems and components that are within the scope of license renewal.

3.6.0.1.2 Staff Safety Evaluation

The staff evaluated the proposed non-EQ cables and connections AMP. The evaluation of the proposed AMP focused on the program elements rather than details of specific plant procedures. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of this SER. To determine whether the AMP is adequate to manage the effect of aging so that there is reasonable assurance that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 7 elements.

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

In addition, as described in the applicant's response to the staff's RAI 3.6-1, this program also includes non-EQ cables and connections associated with sensitive, low-level signal circuits. Note that the only circuits within the scope of license renewal for St. Lucie that fall into this category are those associated with the source, intermediate, and power range neutron detectors. These circuits are susceptible to induced currents from the high voltage power supply if insulation resistance diminishes. The staff noted that the scope of this AMP does not include the high range radiator monitoring cables. The staff met with the applicant on November 7, 2002. In this meeting, the staff requested the applicant to explain why high range radiator monitoring cables were not included in this AMP. The applicant states, in a letter dated November 27, 2002, that the containment radiation monitors (General Atomic, LRA Subsection 4.4.1.17, page 4.4-24) and associated cables (Unit 1- Boston Insulated Wire, LRA Subsection 4.4.1.6, page 4.4.-12, and Raychem Cables, LRA Subsection 4.4.1.7, page 4.4-13), both inside and outside containment at St. Lucie, are managed by the EQ program, and thus require no further discussion. The staff found the applicant's response acceptable because it explains why the high range radiator monitoring cables both inside and outside the containment are not included in the scope of this AMP. The staff also found the scope of the program acceptable because it includes cables and connections that are subject to potentially adverse localized environments that can result in applicable aging effects on these insulated cables and connections.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation, and the staff did not identify the need for such actions.

Parameter Monitored or Inspected: Accessible non-EQ cables and connections within the scope of license renewal in the containment structures installed in adverse localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination. For the cables associated with the source, intermediate and power range neutron detectors, routine calibration tests are performed, based on technical specification that could affect these circuits. The staff found this approach acceptable because visual inspection and calibration programs provide means for monitoring the applicable aging effects for in-scope cables and connections.

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

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

The staff found that the inspection technique for accessible non-EQ cables and connections acceptable on the basis that the AMP is focused on detecting change in material properties of the conductor insulation, which is the applicable aging affect when cables and connections are exposed to an adverse, localized environment. The staff also found that the normal calibration specified in the plant technical specification provides reasonable assurance that aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits will be detected prior to loss of cable intended function.

Monitoring and Trending: In the proposed AMP, the applicant states that trending actions are not included as part of this program because the ability to trend inspection results is limited. For visual inspection, the staff found the absence of trending acceptable because the ability to trend inspection results is limited and the staff did not see a need for such activities. However, for the calibration program, periodic review of calibration results and findings of the plant surveillance will identify the potential existence of aging degradation. Calibration results that are trendable provide additional information on the rate of degradation. In a meeting with the applicant on November 7, 2002, the staff requested the applicant explain why the periodic review of calibration results was not addressed in the calibration program. In response to the staff request, in a letter dated November 27, 2002, the applicant states that although not a requirement in GALL program XI.E2, test results of calibration reports for the source, intermediate, and power range detectors that are trendable will be evaluated to provide additional information on the rate of degradation for these cables. The staff found the applicant's response acceptable because calibration results that are trendable would provide additional information on the rate of degradation.

Acceptance Criteria: One acceptance criteria is that there are no unacceptable visual indications of cables and connection jacket surface anomalies. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. For cables associated with the source, intermediate and power range neutron detectors, the acceptance criteria is specified in the plant procedures. These acceptance criteria are specified in terms of voltage and current limits. The staff found these acceptance criteria acceptable because they should ensure that the cables and connections intended functions are maintained under all CLB design condition for the period of extended operation.

Operating Experience: Operating experience has not identified the presence of adverse localized heat and radiation environments in the containment at St. Lucie. However, operating experience identified by the staff has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers, or hot process pipes, such as feedwater lines. The staff found that the proposed inspection and calibration program will detect the adverse localized environment caused by heat, radiation, or moisture of electrical cables and connections.

3.6.0.1.3 FSAR Supplement

The applicant committed to provide a description of non-EQ cables and connections AMP to be added in the FSAR supplements in Appendix A of the LRA. Pending the staff's receipt of the revised FSAR supplements, this is Confirmatory Item 3.6.2.1-1.

3.6.0.1.4 Conclusion

The staff finds that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connections due to radiation and oxygen will be adequately managed so that there is reasonable assurance that the intended functions of these cables will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.1 Technical Information in the Application

3.6.1.1 Non-Environmentally Qualified Insulated Cables and Connections

In Section 3.6.1.1 of the LRA, the applicant described the process used to identify the applicable aging effects of the electrical/I&C components. The process is based on Department of Energy (DOE) aging management guide (AMG). This AMG provides a comprehensive compilation and evaluation of information on the insulated cables and connections, spliced connections, and terminal blocks. The electrical/I&C non-metallic materials are also evaluated with the cable and connector materials in this AMG. The DOE

Cable AMG evaluated the stressors acting on cable and connection components, industry data on aging and failures of these components, and the maintenance activities performed on cable systems. Also evaluated were the main subsystem within cables—including the conductors, insulation, shielding, tape wraps—and jacketing, as well as all subcomponents associated with each type of connection.

The applicant also identified, evaluated, and correlated the principal aging mechanisms and anticipated effects resulting from environmental and operating stresses with plant experience to determine whether the predicted effects are consistent with field experience. As such, the information, evaluations, and conclusion contained in the DOE Cable AMG are used for the evaluation of aging effects.

The most significant and observed aging mechanisms for insulated cable and connections are listed in the DOE Cable AMG, Table 4-18. The applicant used the aging mechanisms from that table as the starting point for identifying aging effects for insulated cables and connections (spices, terminal blocks, and connectors). The applicant presents the potential aging effects along with the applicable stressors that are evaluated for insulated cables and connections in Table 3.6-1 of the LRA.

3.6.1.1.1 Low-Voltage Metal Connector Contact Surfaces - Moisture and Oxygen

Aging Effects. The applicant states that the DOE Cable AMG, Section 3.7.2.1.3, states that 3 percent of all low-voltage metal connector failures were identified as being caused by moisture intrusion. In each case, the source of moisture was precipitation. Based on the total number of reported connector failures in the DOE Cable AMG, moisture intrusion accounted for only 10 failures in all of the operating plants in the United States.

The applicant indicates structures where electrical/I&C components may be exposed to moisture are in Table 3.6-2 of the LRA. The potential moisture sources from LRA Table 3.6-2 that are applicable to connectors at St. Lucie are precipitation and potential boric acid leaks.

Aging Management Program. The applicant states that all metal connectors are located in enclosures or protected from the environment with Raychem splices. Thus, aging related to moisture and oxygen do not require an AMP for low-voltage connectors at St. Lucie. The applicant also noted that electrical enclosures are treated as structural components and are discussed with each structure, as applicable, in Section 3.5 of the LRA.

3.6.1.1.2 Low-Voltage Metal Compression Fittings—Vibration and Tensile Stress

Aging Effects: The applicant states that the aging mechanism of mechanical stress will not result in aging effects requiring an AMP for the following reasons:

> Damage to cables during installation at St. Lucie is unlikely due to standard installation practices, which include limitations on cable pulling tension and bend radius. Even though installation damage is unlikely, most (including all safety-related) cables are tested after installation and before operation. Failures induced by installation damage generally occur within a short time after the damaged cable is energized.
>
> NRC resolution of License Renewal Issue No. 98-0013, which states, “Based on the above evaluation, the staff concludes that the issue of degradation induced by human activities need not to be considered as a separate aging effect and should be excluded from an AMR.”

> Mechanical stress due to forces associated with electrical faults is mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature.
>
> Vibration is generally induced in cables and connections by the operation of external equipment, such as compressors, fans, and pumps. Vibration can affect cable connections at a running motor by producing fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Normally, there has to be some physical damage as well to have an effect (e.g., a nicked connector). Terminations at equipment are part of the equipment and are inspected and maintained along with the equipment. These terminations are not within the evaluation boundary for insulated cable and connections and are not included in the insulated cable and connection review.
>
> Manipulation of cables is not considered an aging mechanism since such manipulation occurs during maintenance activities. Such activities require post-maintenance testing to detect any deficiency in the cables. Any evidence of cable abnormalities would result in condition being addressed under the corrective program.

Aging Management Program. The applicant concludes that the aging mechanism of mechanical stresses are not aging effects requiring management based on the discussion above.

3.6.1.1.3 Medium-Voltage Cable and Connection Insulations - Moisture and Voltage Stress

Aging Effects: The applicant indicates, in Table 3.6-2 of the LRA, structures where electrical/I&C cable and connectors may be exposed to moisture. From the potential moisture sources identified in LRA Table 3.6-2, precipitation and standing water in the duct bank require further considered for medium-voltage insulation. The effects of moisture-produced water trees on medium-voltage cable were examined in Section 4.1.2.5 of the DOE Cable 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 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cable with cross-linked polyethylene (XLPE) or high molecular weight polyethylene (HMWPE) insulation. However, some cables are located in structures exposed to outside ambient conditions and are evaluated for the potential of moisture-produced water trees.

The applicant also indicates that St. Lucie Units 1 and 2 medium-voltage applications, defined as 2 kV to 15 kV, use lead sheath cable to prevent effects of moisture on the cables. The applicant's cable specification for lead sheath power cables states that lead sheath cables are designed to be installed in wet environments for extended periods. In addition, the cable manufacturer's specification for lead sheath cables states that "... ethylene propylene rubber (EPR)/lead sheath cable is designed for applications in which liquid contamination is present and reliability is paramount. The sheath combined with overall jacket provides a virtually impenetrable barrier against hostile environment - liquids, fire, hydrocarbons, acids, caustic, sewage, etc." As an additional level of protection, underground medium-voltage cables are only routed in concrete-encased duct banks.

Aging Management Program. The applicant indicates that St. Lucie Units 1 and 2, medium-voltage applications, defined as 2 kV to 15 kV, use lead sheath cable to prevent effects of moisture on the cables. The applicant concludes that aging effect related to cable exposed to moisture and voltage stress do not require an AMP at St. Lucie.

3.6.1.1.4 Medium- and Low-Voltage Cable and Connection Insulation - Radiation and Oxygen

Aging Effects. The applicant states that DOE Cable 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 evaluations use the moderate damage dose from the DOE Cable AMG as the limiting radiation value shown in Table 3.6-3 of the LRA. The maximum operating dose shown in LRA Table 3.6-3 includes the maximum 60-year normal exposure for inside containment.

The applicant compares the maximum operating dose and the moderate damage doses in Table 3.6-3 of the LRA and indicates that all of the insulation materials included in this AMR will not exceed the moderate damage doses. The applicant concludes that aging effects caused by radiation exposure will not adversely affect the intended function of insulated cables and connections and electrical/ I&C penetration for the extended period of operation.

Aging Management Program. The applicant states that all of the insulation material will not exceed the moderate damage doses and concludes that aging effects related to radiation do not require an AMP for cables and connections included in the AMR.

3.6.1.1.5 Medium- and Low-Voltage Cable and Connection Insulation - Heat and Oxygen

Aging Effects: The applicant states that a maximum operating temperature was developed for each insulation type based on cable application at St. Lucie Units 1 and 2. The maximum operating temperature indicated in Table 3.6-4 in the LRA incorporates a value for self-heating for power applications combined with the maximum design ambient temperature.

The applicant used Arrhenius method, as described in EPRI NP-1558, “A Review of Equipment Aging Theory and Technology,” to determine the maximum continuous temperature to which the insulation material can be exposed so that the material has an indicated “endpoint of 60 years.” These limiting temperatures for 60 years of service are provided in Table 3.6-4 of the LRA.

The applicant then compares the maximum operating temperature to the maximum 60-year continuous use temperature for the various insulation materials and indicates that except for Hypalon, EPR, and EPDM used in power application, all of the insulation materials used in low- and medium-voltage power cables and connections can withstand the maximum operating temperature for at least 60 years.

For Hypalon, EPR, and EPDM cable insulation, the applicant states that the maximum operating temperatures, including self-heating, is 162 °F. The calculated maximum temperatures for a 60-year life is 154 °F for Hypalon, and 154.9 °F for EPR and EPDM, which are 8.0 °F and 7.1 °F, respectively, less than the maximum operating temperature. The applicant states that the difference is small and is considered to be within the conservatism incorporated in the maximum operating temperatures and the maximum 60-year continuous use temperature.

The applicant states that the maximum temperature for 60-year life in LRA Table 3.6-4 is based on a 50 percent retention-of-elongation for Hypalon, a 40 percent retention-of-elongation for EPR, and a 40 percent loss-of-elongation for EPDM. Since the cables and connections subject to an AMR either will not be subjected to accident conditions or are not required to remain functional during or after an accident, these values can be reduced much further without a loss of function. The Hypalon maximum temperature for 60-year life using 21 percent retention-of-elongation is 167 °F, which is greater than the maximum cable temperature of 162 °F. The EPR and EPDM maximum temperatures for 60-year life using 15 percent retention-of-elongation are 167 °F and 189 °F, respectively, which are also greater than the 162 °F maximum cable temperature.

The applicant states, based on conservatism as discussed above, there is reasonable assurance that Hypalon, EPR, and EPDM insulated cables will not thermally age to the point at which they will not be able to perform their intended function for the period of extended operation.

Aging Management Program: The applicant states that no AMP is required for medium- and low-voltage insulation (cable and connections) due to heat and oxygen.

3.6.1.1.6 Medium- And Low-Voltage Cable and Connection Insulation - Adverse Localized Environments

The applicant states that it performed an extensive review of the St. Lucie Nuclear Plant operating experience associated with cables and connection (connectors, splices, and terminal blocks), in part to determine the existence of adverse localized environments. This review did not identify any adverse localized environments caused by heat or radiation that might be detrimental to cables and connections. In addition, walkdown of accessible non-EQ cables and connections within the scope of license renewal found no adverse localized environments caused by heat or radiation.

The applicant also states that the potential sources of adverse localized heat environments at St. Lucie Units 1 and 2 are from high temperature reactor coolant, main steam, feedwater, and blowdown system piping and components. Most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environment because of the following:

- The intake structures, steam trestle areas, Unit 1 component cooling water area, Unit 1 condensate storage tank enclosure, ultimate heat sink dam, and yard structure are outdoor areas where cable and connections are not subject to adverse localized temperature and radiation effects.

- The turbine building is an outdoor area with no external walls or roofs.

- The reactor buildings, Unit 2 component cooling water area, Unit 2 condensate storage tank enclosure, emergency diesel generator buildings, and fuel handling buildings do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. The reactor auxiliary buildings contain steam blowdown system piping and components in limited areas.

- With regard to radiation, the only buildings with any appreciable radiation levels are the containments, the 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 one percent failed fuel.

The applicant states that containment temperatures are monitored continuously and an average containment temperature is recorded daily, regardless of plant operating mode. For Unit 1, this average is taken from the containment fan cooler inlet temperature detectors (3 of 4 detectors are used). These detectors are located on the 45- and 62-foot elevations of the containment. For Unit 2, the average of the two containment air temperature detectors is used. These detectors are located on the 70-foot elevation of the containment. Per plant operating procedures, the recorded average temperature is required to be less than or equal to 115 °F. Since these temperature detectors are located at elevations that are greater than or equal to that of the electrical equipment within the scope of license renewal, the monitored temperature are considered bounding.

The applicant states containment area radiation levels are monitored continuously by four radiation monitors located in various locations throughout each containment (these monitors are in addition to the safety-related high range radiation, particulate, and gas monitors). Unit 1 UFSAR Section 12.1.4 and Unit 2 UFSAR Section 12.3.4 describes the area radiation monitoring system. High radiation activity in the vicinity of any of these containment monitors is indicated, recorded, and alarmed in the control room. Note that all cable and connection insulation materials that are located within the containment are the same as cable and connection insulation materials already included in the EQ program at St. Lucie. The area radiation monitoring system has 59 monitors (26 in Unit 1 and 33 in Unit 2) located throughout the 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 walkdown and periodic health physic radiation monitoring (surveys of areas in the reactor auxiliary building and fuel handling building are conducted at least monthly, and in some cases daily or weekly). Additionally, all plant personnel are trained to use the plant’s corrective action program if conditions adverse to quality, which would include abnormal environmental conditions, are observed. Any change in temperature that could adversely affect non-EQ cables and connections would be readily noticed. The same applies for radiation. The normal 40-year radiation doses are based on the assumption of operation with one percent failed fuel. This is conservative because St. Lucie Units 1 and 2 have never operated with more than one percent failed fuel. Therefore, changes in local dose rates that would effect the life of equipment would have to be so significant that they would be readily identified.

In addition, the applicant states that 60-year life maximum temperature and radiation values for non-EQ cable and connection insulation materials are also conservative. The typical “endpoint” for cable thermal aging data is 40 percent to 60 percent retention-of-elongation. Research funded by the NRC, and published in NUREG/CR-6384, determined that the retention-of-elongation of most cable insulation materials can be reduced to zero percent, and the insulation will still be capable of withstanding a LOCA and remain functional. As the insulated cables and connections subject to an AMR will either not be subject to an accident environment or are not required to function after being subject to an accident environment, the endpoint chosen for this review is extremely conservative. The insulated cable and connection materials could be aged a great deal more, possibly to the point where retention-of-elongation reaches zero percent, without loss of intended function. Preliminary results of the EQ research on low-voltage electrical cables were presented by Brookhaven National Laboratories at an NRC public meeting on March 19, 1999. Preliminary conclusion from LOCA tests 1, 2, and 3 of the NRC research program indicated that, “Electrical cable with insulation elongation-at-break values as low as 5 percent performed acceptable under accident conditions.” Therefore, the useable 60-year life temperature for a typical cable insulation is significantly higher than the values shown in Table 3.6-4 of the LRA. Table 3.6-3 of the LRA shows that the radiation values that non-EQ and connection insulation materials can withstand are much greater than actual design values for the 60-year life of the plant.

The applicant concludes that based on the original St. Lucie Units 1 and 2 cable routing designs, plant-specific operating experience, and period walkdowns that have been performed, there are no adverse localized environments caused by heat or radiation present in areas where non-EQ cables and connections are located.

3.6.1.2 Uninsulated Ground Conductors

3.6.1.2.1 Aging Effects

The applicant states that the ground cable material used at St. Lucie Units 1 and 2 is copper. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong, and it is easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical-type connectors, which include compression-, bolted-, and wedge-type devices.

The applicant states that a review of available technical information regarding material aging revealed that there are no aging effects requiring management for copper grounding materials. In addition, a review of industry and plant operating experiences did not identify any failures of copper grounding systems due to aging effects.

3.6.1.2.2 Aging Management Program

The applicant states that based on industry and plant-specific experiences, no aging effects requiring management were identified for the plant grounding system. The applicant also reviewed industry and plant operating experience to ensure that no unique aging effects exist beyond those discussed in Section 3.6 for cables and connections.

3.6.2 Staff Evaluation

The staff evaluated the information on aging management presented in the LRA, Section 3.6.1 and in the applicant’s response to the staff RAIs, dated November 27, 2002, to determine whether the aging effects for non-EQ insulated cables and connections have been properly identified and will be adequately managed consistent with its CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s AMR for aging effects and the applicant’s AMP credited for the aging management of non-EQ insulated cables and connections at St. Lucie Nuclear Station. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the non-EQ insulated cables and connections (terminal blocks, connectors, and splices).

3.6.2.1 Non-Environmentally Qualified Insulated Cables and Connections

3.6.2.1.1 Low-Voltage Metal Connector Contact Surfaces - Moisture and Oxygen

Aging Effects. The potential aging mechanisms considered for low-voltage metal connector surfaces is corrosion due to moisture intrusion. Structures where electrical/I&C components may be exposed to moisture are indicated in the LRA Table 3.6-2. The potential moisture sources from this table that are applicable to connectors at St. Lucie are precipitation and potential boric acid leaks. Table 3.6-1 of the LRA indicates increased resistance and heating, high resistance, and loss of circuit continuity are the potential aging effects for low-voltage metal connector contact surfaces and compression fitting. The staff concurred with the aging effects identified above by the applicant for the low-voltage metal connector surfaces. High resistance and loss of circuit continuity are the potential aging effects for low-voltage metal connector surfaces.

Aging Management Program. The staff finds that because low-voltage connectors are located in an enclosure or protected from the environment with Raychem splices, there is no aging effect related to moisture and oxygen, and an AMP for low-voltage connectors is not required.

Conclusion. On the basis of the staff's evaluation above, the staff concludes that the applicant has demonstrated that the aging effects associated with low-voltage metal connector contact surfaces will be adequately managed so that there is reasonable assurance that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.2 Low-Voltage Metal Compression Fitting - Vibration and Tensile Stress

Aging Effects. The aging mechanism of mechanical stress will not result in aging effects requiring management for the following reasons:

- damage to cables during installation at St. Lucie is unlikely due to standard installation practice, which include limitation on cable pulling tension and bend radius

- NRC resolution of License Renewal Issue No. 98-0013 which states that the issue of degradation induced by human activities need not be considered as a separate aging affect and should be excluded from an AMR

- mechanical stress due to forces associated with electrical faults is mitigated by the fast action of circuit protective devices at high currents. However, the mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature

- vibration is generally induced in cables and connections by the operation of external equipment, such as compressor, fans, and pumps. Vibration can affect cable connections at a running motor by producing fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Normally, there has to be some physical damage as well to have an effect (e.g., a nicked connector). Terminations at equipment are part of the equipment and are inspected and maintained along with the equipment. These terminations are not within the evaluation boundary for insulated cable and connections and are not included in the insulated cable and connection review; and

- manipulation of cables is not considered an aging mechanism since such manipulation occurs during maintenance activities. Such activities require post-maintenance testing to detect any deficiencies in the cables. Any evidence of cable abnormalities would result in the condition being addressed under the corrective action program.

Aging Management Program. Because mechanical stress will not result in aging effects, an AMP for low-voltage metal compression fittings is not required for St. Lucie.

Conclusion. On the basis of the staff's evaluation above, the staff concludes that damage to low-voltage metal compression fitting during installation, electrical faults, vibration, and manipulation of cables are not considered aging mechanisms that result in aging effects. The applicant has demonstrated that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.3 Medium-Voltage Cable and Connection Insulations - Moisture and Voltage Stress

Aging Effects. Structures where electrical/I&C cable and connectors may be exposed to moisture are indicated in Table 3.6-2 of the LRA. Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture. These trees eventually result in breakdown of the dielectric materials and ultimately failure. The growth and propagation of water trees is somewhat unpredictable and occurrences have been noted for cable operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cable with conductor insulation made by various organic polymers (e.g., XLPE and HMWPE). The staff concurs with the applicant's determination that formation of water trees are applicable aging effects for the inaccessible non-EQ medium-voltage cables caused by moisture and voltage stress.

Aging Management Program. St. Lucie Units 1 and 2 medium-voltage applications use lead sheath to prevent effects of moisture on the cables. The cable specification states that lead sheath cables are designed to be installed in wet environments for extended periods. In addition, the cable manufacturer specification for lead sheath cable states that "...EPR/lead sheath cable is designed for application in which liquid contamination is present and reliability is paramount. The sheath combined with the overall jacket provided a virtually impenetrable barrier against hostile environments - liquids, fire hydrocarbons, acids, caustic, sewage, etc." As an additional level of protection, St. Lucie underground medium voltage cables are only routed in concrete encased duct banks.

The staff concludes that since the applicant uses lead sheath medium-voltage cables which are specifically designed for use in wet environments, an AMP to manage the water treeing for medium-voltage cable is not required.

Conclusion. On the basis of the staff's evaluation above, the staff concludes that the applicant has demonstrated that the aging effects associated with inaccessible medium-voltage cables will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.4 Medium- and Low-Voltage Cable and Connection Insulation - Radiation and Oxygen

Effects of Aging. Section 3.6.1.1.4 of the LRA evaluates the aging effects applicable for electrical components that can be expected to occur due to radiation. The applicant states that the DOE Cable AMG, Section 4.1.4, provides a threshold value and a moderate dose for various insulating materials. The threshold value is the amount of radiation that causes incipient to mild insulation damage. Once this threshold is exceeded, damage to the insulation increases from mild to moderate to severe as the total dose increases. The moderate damage value indicates the value at which the insulating material has been damaged but is still functional. St. Lucie Units 1 and 2 evaluations use the moderate damage dose from the DOE Cable AMG as the limiting radiation value shown in Table 3.6-3 of the LRA. The maximum dose shown in LRA Table 3.6-3 includes the maximum 60-year normal exposure inside containment. The applicant concludes that because the maximum operating radiation dose to cable insulation will not exceed the moderate damage doses, no aging management is required for radiation.

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment. Conductor insulation materials used in cable and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is limited to a certain plant area that is significantly more severe than the specific service condition for the cables and connections. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Radiation-induced degradation in cable jacket and insulated materials produces change in organic material properties, including reduced elongation and tensile strength. Visible indication of radiative aging may include embrittlement, cracking discoloration, and swelling of the jacket and insulation material. The aging effects identified above require aging management. The purpose of the AMP is to provide reasonable assurance that the intended functions of electrical cables and connections exposed to adverse localized environments caused by radiation will be maintained consistent with the CLB through the period of extended operation.

For the St. Lucie units, the intake structures, steam trestle areas, Unit 1 component cooling water area, Unit 1 condensate storage tank enclosure, ultimate heat sink dam, and yard structure are outdoor areas where cable and connections are not subject to adverse localized temperature and radiation effects. The turbine buildings are outdoor areas with no external walls or roofs. The reactor buildings, Unit 2 component cooling water area, Unit 2 condensate storage tank enclosure, emergency diesel generator buildings, and fuel handling buildings do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. The reactor auxiliary buildings contain steam blowdown system piping and components in limited areas. With regard to radiation, the only buildings with any appreciable radiation levels are the containments, the 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.

The applicant concludes that because the maximum operating radiation dose to cable insulation will not exceed the moderate doses, no aging management is required for radiation. The applicant's conclusion is not consistent with the AMP and activities for electrical cables and connections exposed to localized environments caused by radiation as described in the previous LRAs that have been approved by the staff. The staff requested the applicant to provide a description of an AMP for accessible non-EQ electrical cables and connections (connectors, splices, and terminal blocks) within the scope of license renewal located in the containment exposed to an adverse localized environment caused by radiation or moisture.

The applicant responded in a letter dated September 26, 2002, stating that based on the original St. Lucie cable routing design, plant-specific operating experience, and periodic walkdowns, there are no adverse localized environments caused by heat, radiation, or moisture present in areas where non-EQ cables and connections are located. As indicated in LRA section 3.6.2.2 (page 3.6-9), the applicant performed an extensive review of St. Lucie plant operating experience associated with cables and connections, in part, to determine the existence of adverse localized environments. This review did not identify any adverse localized environments caused by heat, radiation, or moisture that might be detrimental to cables and connections. Occurrences of degraded cable are identified and dispositioned routinely through the corrective action and maintenance programs. Due to the absence of adverse localized environments caused by heat, radiation, or moisture in areas where non-EQ cables and connections are present, inspection of these non-EQ cables and connections would be of little value. However, based on discussions with the staff, the applicant proposed an AMP for non-EQ cables and connections in the St. Lucie containments. The non-EQ cables and connections managed by this program include those used for power and instrumentation and control that are within the scope of license renewal. The staff finds the applicant's response acceptable because it proposes an AMP that will manage the aging effects caused by heat, radiation, or moisture. The staff evaluated this AMP in Section 3.6.0.1 of this SER.

In a letter dated May 16, 2002, the NRC forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists, a proposed interim staff guidance (ISG) on screening of electrical fuse holders. The staff position indicated that fuse holders should be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This position only applies to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered to be piece parts of the larger assembly and not subject to an AMR.

The intended functions of a fuse holder are to provide mechanical support for the fuse and to maintain electrical contact with the fuse blades or metal end caps to prevent the disruption of the current path during normal operating conditions when the circuit current is at or below the current rating of the fuse. Fuse holders perform the same primary function as connections by "providing electrical connections to specified sections of an electrical circuit to deliver rated voltage, current, or signals." These intended functions of fuse holders meet the criteria of 10 CFR 54.4(a). In addition, these intended functions are performed without moving parts or without a change in configuration or properties as described in 10 CFR 54.21(a)(1)(i). The fuse holders into which fuses are placed are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of copper.

Operating experience as discussed in NUREG-1760 (Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants) identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. The final staff position on this issue is under development in discussions with NEI. In the meeting with the applicant on November 6, 2002, the staff requested that the applicant provide details of AMR of fuse holders, and commit to implement, at St. Lucie Units 1 and 2 the final resolution of the ISG.

In response to the staff request, in a letter dated November 22, 2002, the applicant states that with regard to the AMR of fuse holders, as stated in the applicant's response to RAI 2.5-1, fuse holders that were not part of a larger, active assembly were scoped, screened, and determined to be subject to an AMR. The only fuse holders determined to require an AMR were those installed to address the requirements of Regulatory Guides (RGs) 1.63 and 1.75 to provide double isolation for non-safety-related loads powered from safety-related power supplies. These fuses are located in a number of isolation panels located in the reactor auxiliary buildings. These panels are enclosures that contain the fuse, fuse holders, and cables associated with them. As provided in LRA Section 3.6 (pages 3.6-1 through 3.6-16), the AMR for connections (including the fuse holders above) addressed the aging mechanisms of moisture, oxygen, vibration and tensile stress, radiation, and heat. The AMR also addressed averse localized environments. As indicated above, the AMR concluded that there were no aging effects requiring management for electrical connections.

The applicant also stated that based on its review of NUREG-1760, the only aging mechanism not explicitly addressed in the LRA for fuse holders is wear/fatigue due to repeated insertion and removal of fuses. For St. Lucie, the fuse holders subject to AMR are those associated with fuses that are not routinely removed for maintenance and/or surveillance. When these circuits need to be de-energized, power is removed at the safety-related power supplies (motor control centers, power panels, etc.). Based on the information provided above, the applicant concludes that there are no aging effects requiring management for fuse holders. However, in the meeting with the applicant on November 6, 2002, the staff has requested that the applicant make a commitment to implement the final resolution of the ISG regarding fuse holders currently under discussion with the industry. The applicant stated that it will address the revision to the ISG regarding fuse holders (when issued) as applicable to St. Lucie.

Operating experience as discussed in NUREG-1760 identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. On this basis, fuse holders (including both the insulation material and the metallic clamps) are subject to both an AMR and AMP for license renewal. Typical plant effects observed from fuse holder failure due to aging have resulted in challenges to safety systems, cable insulation failure due to over-temperature, failure of containment spray pump to start, a reactor trip, etc. Therefore, managing age-related failure of fuse holders would have a positive effect on the safety performance of a plant. Information Notices 91-78, 87-42, and 86-87 are examples that underscore the safety significance of fuse holders and the potential problems that can arise from age-related fuse holders failure. The staff disagreed with the applicant that there were no aging effects requiring management for fuse holders. This is open item 3.6.2.1-1.

Low-Level Instrumentation Circuits. In the previous LRA, the applicant did not provide an AMP for electrical cables used in low-level instrumentation circuits. Instead, it proposed visual inspection for detecting aging degradation of these cables from heat or radiation. Exposure of electrical cables to localized environments caused by heat or radiation can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation, since it may contribute to inaccuracies in instrument loop. Visual inspection may not be sufficient to detect aging degradation from heat and radiation in the instrumentation circuits with sensitive, low level signal. Because low level signal instrumentation circuits may operate with signals that are normally in the pico-amp range or less, they can be affected by extremely low-levels of leakage current. These low-levels of leakage current may affect instrument loop accuracy before the adverse localized environment that caused them produces changes that are visually detectable. Routine calibration test performed as part of the plant surveillance test program can be used to identify the potential existence of this aging degradation. In a letter to the applicant dated July 1 and July 18, 2002, (RAI Number 3.6-2), the staff requested the applicant to provide a description of the AMP that will be relied upon to detect this aging degradation in sensitive, low-level signal circuits.

In response to the staff's request, in a letter dated September 26, 2002, the applicant stated that the AMRs it performed on non-EQ cables and connections determined that there were no aging effects that require management for the extended period of operation. These reviews included an assessment of aging degradation of non-EQ cables and connections associated with sensitive, low-level signal circuits. A review of plant-specific operating experience performed as part of these AMRs (see LRA Section 3.6.2.2, page 3.6-9), which included a review of instrument calibration results and discussion with St. Lucie plant maintenance and engineering personnel, indicated that no failures of cables and connections associated with sensitive, low-level signal circuits have occurred due to aging.

- As stated in the applicant's response to the staff's RAI 3.6-1, the applicant states that the only non-EQ cables and connections associated with sensitive, low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the source, intermediate, and power range neutron detectors. The applicant does not consider an additional AMP to address sensitive, low-level signal circuits to be necessary for the following reasons:

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

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

- The Electrical Cable and Termination Aging Management Guideline, SAND 96-0344 concludes in Section 1.4 that "....reliance on visual inspection techniques for the assessment of low-voltage cable and termination aging appears warranted since these techniques are effective at identifying degraded cables." The applicant also stated that additional review of other license renewal SERs indicates acceptance of visual inspection for managing aging of cables and connections.

However, based on discussion with the staff in a public meeting on September 4 and 5, 2002, the applicant has included activities in the AMP proposed in the response to RAI 3.6-1 to address aging of the sensitive circuits associated with the source, intermediate, and power range neutron detectors. The results of routine calibration tests for these circuits will be used to facilitate detection of adverse localized environments. The acceptability of the combined program is evaluated in the non-EQ cables and connections AMP.

Conclusion. Based on the review of the LRA and the applicant's response to the staff's RAIs, except for open item 3.6.2.1-1, the staff concludes that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connections due to radiation and oxygen will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.5 Medium- and Low-Voltage Cable and Connection Insulation - Heat and Oxygen

Effects of Aging. Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and changes in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation.

Section 3.1.1.5 of the LRA evaluates the aging effects applicable for electrical components due to heat and oxygen. The applicant states that it developed a maximum operating temperature for each insulation type based on cable applications at St. Lucie Units 1 and 2. The maximum operating temperature indicated in LRA Table 3.6-4 incorporates a conservative value for self-heating for power applications combined with the maximum design ambient temperature. The applicant used the Arrhenius method, as described in EPRI NP-1558, to determine the maximum continuous temperature to which insulation can be exposed so that the material has an indicated "endpoint of 60 years." The applicant concludes that a comparison of the maximum operating temperature to the maximum 60-year continuous use temperature for the various insulation materials indicates that all of the insulation material used in medium- and low-voltage power cables and connections can withstand the maximum operating temperature for at least 60 years. Therefore, no aging effects were identified for medium- and low-voltage cable and connection insulation due to heat and oxygen.

The most common adverse localized environments are those created by elevated temperature. Elevated temperature can cause equipment to age prematurely, particularly equipment containing organic materials and lubricants. The effect of elevated temperature can be quite dramatic. The types of areas that are prone to high temperature include areas with high temperature process fluid piping and vessels, areas with equipment that operate at high temperature, and areas with limited ventilation. It is not clear to the staff that the Arrhenius method can be used to extend the qualified life of the insulation material exposed to elevated localized temperature conditions to 60 years. The applicant's conclusion is not consistent with the AMP and activities for electrical cables and connections exposed to adverse localized environments caused by heat as described in the previous LRAs that have been approved by the staff. In a letter dated July 1, 2002, the staff requested that the applicant describe an AMP for accessible and inaccessible electrical cables and connections exposed to adverse localized environments caused by heat or moisture.

In response to the staff's request, in a letter dated September 26, 2002, the applicant stated that most areas of the St. Lucie Nuclear Plant are not likely to have adverse localized heat environments. The reactor buildings do not contain any high temperature reactor coolant, main steam, and feedwater system piping and components. Although, the reactor auxiliary buildings contain blowdown system piping and components, the piping runs are limited to the mechanical penetration areas, and are not located near electrical cables and connections. Due to the absence of adverse localized environments caused by heat or moisture in areas where non-EQ cables and connections are present, inspection of these non-EQ cables and connections would be of little value. However, based on the discussion with the staff, the applicant proposed an AMP for non-EQ cables and connections in the St. Lucie containments. The staff finds the applicant's response acceptable because it proposes an AMP that will manage the aging effects caused by heat, radiation, or moisture.

<u>Aging Management Program.</u> The staff has evaluated the Non-EQ cables and connections AMP for cables and connections exposed to potential adverse localized environment caused by heat and oxygen. The acceptability of this program is evaluated in the staff SER Section 3.6.2.1.4 under Aging Management Program.

<u>Conclusion</u>. The staff concludes that the applicant has demonstrated that the aging effects of medium- and low-voltage cables and connection due to heat and oxygen will be adequately managed so that there is a reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 Uninsulated Ground Conductors

3.6.2.2.1 Aging Effects

The ground cable material used at St. Lucie Units 1 and 2 is copper. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong, and it is easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical-type connectors, which include compression-, bolted-, and wedge-type devices.

The applicant has reviewed the available industry technical information regarding material aging and has determined that there are no aging effects requiring management for copper grounding materials. In addition, the applicant has reviewed the industry and plant operating experience and did not identify any failures of copper ground system due to aging affects. Therefore, based on industry and plant-specific experience, no aging affects requiring management were identified for the plant grounding system. The staff concurs with the applicant that there are no aging effects identified for copper grounding material because copper has high corrosion resistance and operating experience did not identify any failure of copper ground systems.

3.6.2.2.2 Aging Management Program

The staff agrees with the applicant that no AMP is required for the uninsulated ground conductor because no aging effect is identified for uninsulated ground conductors.

3.6.3 Conclusion

The staff reviewed the information provided in Sections 3.6.1.1.1, 3.6.1.1.2, 3.6.1.1.3, 3.6.1.1.4, 3.6.1.1.5, and 3.6.1.1.6 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of this review and the above evaluation, except Open Item 3.6.2.1-1, the staff finds that the applicant has demonstrated that the aging effects associated with non-EQ cables and connections will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4 Station Blackout System

3.6.4.1 Technical Information in the Application

By a letter dated April 1, 2002, the staff issued a staff position to NEI, which clarified the use of alternate AC power source within the context of the Station Blackout (SBO) Rule and described that the offsite power system, which is used to connect the plant to the offsite power source, should be included within the scope of license renewal. The implementation of this staff position will begin with LRAs that are currently under review, such as St. Lucie Units 1 and 2. Consistent with the staff's position described in the aforementioned letter, the staff requested the applicant, in RAI 2.1-2, to describe the process it used to evaluate the SBO portion of the criterion defined in 10 CFR 54.4(a)(3). As part of the response, the staff requested the applicant list those additional SSCs included within scope and list those structures and components for which AMRs were conducted, and describe the AMPs that will be credited for managing the identified aging effects. In a letter dated September 26, 2002, the applicant responded that restoration of offsite power is not relied on to meet the requirements of the SBO Rule for St. Lucie. However, based on the staff guidance provided in the April 1, 2002, letter, and RAI 2.1-2, the applicant has performed an evaluation to determine the additional electrical and structural components that are in the scope of license renewal for restoration of offsite power at St. Lucie.

The applicant stated that additional components included in the scope of license renewal as meeting the scope criteria of 10 CFR 54.4(a)(3) for restoration of offsite power are as follows:

- circuit breakers and switches to connect the startup transformer circuits to the grid
- batteries and DC controls associated with startup transformer circuit breakers
- startup transformers
- non-safety-related 4.16 kV switchgear
- DC control and power (lead sheath) cables
- all aluminum alloy conductor (Type AAAC) transmission conductors between the startup transformers and circuit breakers
- high voltage insulators associated with the transmission conductors
- switchyard bus and connections between the startup transformers and circuit breakers

- nonsegregated-phase bus between the startup transformers and the non-safety-related 4.16 kV switchgear.

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

3.6.4.1.1 Type AAAC Transmission Conductors

The applicant states that the Type AAAC transmission conductors at St. Lucie are constructed of an aluminum core and strand. The aging effects for transmission conductors requiring evaluation are loss of conductor strength and those associated with vibration. The most prevalent mechanism contributing to loss of conductor strength of transmission conductor is corrosion. Corrosion is not an aging mechanism of concern for Type AAAC transmission conductors because they are constructed entirely of aluminum which is resistant to corrosion.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. The St. Lucie Units 1 and 2 conductors are 1081 MCM Type AAAC, and they are designed and installed in accordance with NESC. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old transmission conductor. Assuming a 30 percent loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength.

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

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

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to transmission conductors. The applicant states that it also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for transmission conductors. This review included non-conformance reports, license event reports, and condition reports for any documented instances of transmission conductor aging, in addition to interviews with responsible transmission engineering personnel. No unique aging effects were identified from this review beyond those discussed above.

3.6.4.1.2 High Voltage Insulators

The applicant states that high voltage insulators are constructed of the following materials:

- porcelain
- cement
- aluminum

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

Various airborne materials, such as dust, salt, and industrial effluents, can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. This has been confirmed by St. Lucie experience. Therefore, surface contamination of St. Lucie Units 1 and 2 high-voltage insulator is not an aging effect requiring management for the period of extended operation.

Loss of material due to mechanical wear is an aging effect for strained and suspended insulators if they are subject to significant movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact points of the insulator string, and between an insulator and the supporting hardware. Although loss of material due to wear is possible, industry experience has shown that if they begin to swing in a substantial wind, the swinging will stop when the wind subsides. Therefore, loss of material due to wear of the St. Lucie Units 1 and 2 high voltage insulators is not an aging effect requiring management for the period of extended operation.

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, a review of industry experience was performed. This review included NRC generic communications and industry operating experience related to transmission insulators. The following document related to insulators was identified in this review—IN 93-95, "Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators."

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

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

3.6.4.1.3 Switchyard Buses and Connections

The applicant states that switchyard buses and connections are constructed of the following:

- aluminum
- bronze

- copper

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

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

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

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

3.6.4.2 Staff Evaluation

This section provides the staff's evaluation of those SBO electrical components within the scope of license renewal and requiring an AMR. The staff reviewed this section to determine whether the applicant has demonstrated that the aging effects associated with SBO of the systems and components will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.4.2.1 Type AAAC Transmission Conductors

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

NESC requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. The St. Lucie Units 1 and 2 conductors are 1081 MCM Type AAAC, and they are designed and installed in accordance with NESC. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old transmission conductor. Assuming a 30 percent loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength. This is further supported by the fact that the applicant has been installing and maintaining transmission conductors on its transmission system for more than 60 years and has not had to replace any conductors due to aging problems.

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

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, the applicant performed a review of industry experience. This review included the staff generic communications and industry operating experience related to transmission conductors. The applicant states that it also reviewed St. Lucie Units 1 and 2 operating experience to validate aging effects for transmission conductors. This review included non-conformance reports, license event reports, and condition reports for any documented instances of transmission conductor aging, in addition to interviews with responsible transmission engineering personnel. No unique aging effects were identified from this review beyond those discussed above.

Based on the materials, NRC generic communications, and St. Lucie operating experience, there are no aging effects requiring aging management for transmission conductors for the period of extended operation. The staff agrees with the applicant that no AMP is required for transmission conductors.

3.6.4.2.2 High Voltage Insulators

The high voltage insulators are constructed of the following materials:

- porcelain
- cement
- aluminum

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

Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. This has been confirmed by St. Lucie experience. Therefore, surface contamination of St. Lucie Units 1 and 2 high voltage insulator is not an aging effect requiring management for the period of extended operation.

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

In order to validate aging effects and to assure no additional aging effects exist beyond those discussed above, the applicant performed a review of industry experience. This review included NRC generic communications and industry operating experience related to transmission insulators. The following document related to insulators was identified in this review—IN 93-95, "Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators."

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

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

On the basis of its review of industry information, NRC generic communications, and St. Lucie operating experience, the staff concludes that there are no aging effects requiring aging management for high voltage insulators for the period of extended operation. The staff agrees with the applicant that no AMP is required for transmission insulators.

3.6.4.2.3 Switchyard Buses and Connections

The switchyard buses and connections are constructed of the following:

- aluminum
- bronze
- copper

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

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

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

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

On the basis of its review of industry information, NRC generic communications, and St. Lucie operating experience, the staff concludes that there are no aging effects requiring aging management for high voltage insulators for the period of extended operation. The staff agrees with the applicant that no AMP is required for switchyard buses and connections.